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PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates — 6690-UR-124

FINAL DECISION

This is the Final Decision in the application of Wisconsin Public Service Corporation (WPSC) for authority to adjust Wisconsin retail electric and natural gas rates in 2016.

Final electric rate changes are authorized consisting of a $7,874,000 annual rate decrease for Wisconsin retail electric operations, a 0.78 percent decrease. Final natural gas rate changes are authorized consisting of a $6,225,000 annual rate decrease for Wisconsin natural gas operations, a 2.06 percent decrease.

Introduction

On April 17, 2015, WPSC filed an application with the Commission requesting authority to increase its electric and natural gas rates effective January 1, 2016. Its filing indicated revenue deficiencies of $94.1 million, or 9.4 percent, for Wisconsin retail electric operations, and $9.1 million, which is 2.7 percent of total revenues or 7.3 percent of margin revenues, for Wisconsin natural gas operations. On May 6, 2015, WPSC revised its request in order to correct some errors in its original filing. The revised request indicated revenue deficiencies of $96.9 million, or 9.7 percent, for Wisconsin retail electric operations and $9.1 million, which is 2.7 percent of total revenues or 7.3 percent of margin revenues, for Wisconsin natural gas operations. WPSC's rate increase request reflects a 10.2 percent return on common stock equity.

On June 11, 2015, a prehearing conference was held in Madison, Wisconsin, to determine the issues to be addressed in this docket and to establish a schedule for the proceeding. On September 9, 2015, public hearings were held in De Pere, Wisconsin, for members of the general public. The Commission received over 300 comments from members of the public as part of the Commission's public hearing process that included the opportunity to submit written comments through the Commission's web site or at the hearing, or to testify at the public hearing.

The Commission considered this matter at its open meeting of November 19, 2015. Appendix A lists the parties for purposes of review under Wis. Stat. §§ 227.47 and 227.53. Others who appeared are listed in the Commission's files.

Findings of Fact

1. WPSC is an investor-owned electric and natural gas public utility as defined in Wis. Stat. § 196.01(5)(a), providing electric and natural gas service to north-central and northeast Wisconsin.

2. Presently authorized rates for WPSC's Wisconsin retail electric utility operations will produce total operating revenues of $1,059,608,000 for the test year ending December 31, 2016, which results in an adjusted net operating income of $148,526,000 and an annual revenue excess of $7,874,000. Presently authorized rates for WPSC's Wisconsin natural gas utility operations will produce total operating revenues of $304,024,000 for the test year ending December 31, 2016, which results in an adjusted net operating income of $32,485,000 and an annual revenue excess of $6,225,000.

3. For the Wisconsin retail electric utility, the estimated rate of return on average net investment rate base of $1,745,688,000 at current rates subject to the Commission's jurisdiction for the test year is 8.51 percent, which is excessive.

4. For the Wisconsin natural gas utility, the estimated rate of return on average net investment rate base of $368,902,000 at current rates subject to the Commission's jurisdiction for the test year is 8.81 percent, which is excessive.

5. A reasonable decrease in operating revenue for the test year to produce an 8.24 percent return on WPSC's average net investment rate base for Wisconsin retail electric operations is $7,874,000.

6. A reasonable decrease in operating revenue for the test year to produce a 7.80 percent return on WPSC's average net investment rate base for natural gas operations is $6,225,000.

7. WPSC's filed operating income statements and net investment rate base for the test year, as adjusted for Commission decision, are reasonable.

8. The Commission finds that reasonable total company fuel costs (all fuel costs) are $534.4 million. The Commission finds that a reasonable 2016 fuel cost plan level of monitored fuel costs is $368,042,000, which reflects the costs of generation and purchased energy, minus revenue from opportunity sales of energy and capacity. The reasonable 2016 fuel cost plan also reflects the decreased margin on natural gas used for electric generation, purchased from WPSC's own gas utility. The fuel cost plan year monitored fuel cost divided by the authorized level of native requirements of 13,900,713 megawatt-hours (MWh) results in an average net monitored fuel cost per MWh of $26.48.

9. It is reasonable to monitor WPSC's fuel costs, using a plus or minus 2 percent bandwidth, as provided in Wis. Admin. Code § PSC 116.06(3).

10. The fuel cost data in Appendix D shall be used for monitoring WPSC's 2016 fuel costs.

11. It is reasonable to exclude from recovery any uneconomic dispatch costs associated with the seasoning of the Reactivated Coke Technology (ReACT™)[1] activated coke pellets after the first 6 months of seasoning.

12. It is reasonable to direct WPSC to file a report with the Commission for the preceding quarter, on any potential ReACT™ liquidated damages, both those that are pursued and those not pursued, the latter accompanied by an explanation as to why they were not pursued.

13. It is premature at this time to make a determination as to how liquidated damages under the ReACT™ contract, if any, should be treated for ratemaking purposes.

14. It is reasonable and consistent with Commission accounting practices to capitalize the costs for activated coke and ammonia consumed during Minimum Performance Testing conducted prior to the placement of the ReACT™ system in service.

15. It is reasonable to extend the escrow treatment of network transmission charges and credits from American Transmission Company LLC (ATC) and the Midcontinent Independent System Operator, Inc. (MISO) through 2016. This would include any Federal Energy Regulatory Commission (FERC) ordered ATC and MISO retroactive transmission asset rate of return refunds and any System Support Resource (SSR) costs and credit true-ups which shall also be escrowed for return to, or collection from, ratepayers in a subsequent fuel reconciliation or rate case proceeding.

16. It is reasonable that the actual October ATC transmission expense true-ups be included as part of the transmission expense update.

[1] ReACT™ is the trade name for the Reactivated Coke Technology system.

17. It is reasonable that the deferral of rail take-or-pay penalties be continued through the test year.

18. It is reasonable to increase WPSC test-year fuel costs by an estimated $190,000 due to WPSC self-supplying the Fox Energy Center.

19. As discussed in the Opinion section of this Final Decision, it is not reasonable to take any additional action with respect to using the most recent 12 months Locational Marginal Prices (LMP) at Crane Creek, requiring additional post-audit review of purchased power agreements, and imposing a refund requirement with respect to refunds that may be ordered by FERC.

20. It is reasonable to update fuel costs via delayed exhibit submission to account for November 4, 2015, forecasts for coal, rail, natural gas costs on electric fuels costs, purchased power costs, purchased capacity costs, risk management costs, opportunity sales revenues and interruptible revenue credits.

21. A reasonable sales forecast for the Rg-1 electric rate schedule is 2,641,483,704 kilowatt-hours (kWh).

22. A reasonable sales forecast for the Cg-20 200-500 URB electric rate schedule is 2,022,508,741 kWh.

23. A reasonable sales forecast for the Rg-3 natural gas residential rate schedule is 242,470,845 therms.

24. A reasonable sales forecast for the Cg-FS natural gas rate schedule is 80,366,168 therms.

25. A reasonable sales forecast for the Cg-FM rate schedule is 56,291,620 therms and fixed charge counts of 1,248.

26. A reasonable sales forecast for the sale of natural gas transportation services to the CG-TSL-IG2T rate schedule is 230,948,744 therms, which uses WPSC's original filed estimate plus an additional 19.5 million therms associated with the closure of the Coal Displacement Gas Transportation tariff.

27. In future rate case filings, it is reasonable for WPSC to provide weather-normalized sales data for electric and natural gas operations at the rate schedule level.

28. A reasonable wage increase to use in the bridge year (2015) in the calculation of the 2016 test-year payroll expense is 1.3 percent.

29. It is not reasonable to include in revenue requirement the cost of the 13 executives who received change-in-control terminations as a result of WEC Energy Group's acquisition of Integrys Energy Group, Inc. (Integrys)

30. It is not reasonable to include in revenue requirement the cost of incentive compensation.

31. It is not reasonable to include in revenue requirement the cost of incentive compensation for Columbia and Edgewater.

32. It is reasonable to use a 3-year average to forecast storm damage expense.

33. It is not reasonable to reduce the test-year estimate of uncollectible accounts expense by 25 percent to reflect the credit delays associated with the implementation of the Integrys Customer Experience (ICE) project.

34. The reasonable level of expensed conservation costs recoverable in rates for the 2016 test year is $16,346,123 for electric utility operations and $3,280,459 for natural gas utility operations. The level for electric utility operations consists of the conservation budget of $16,046,221 plus an escrow amortization adjustment of $299,902. The electric escrow

adjustment represents the test-year amortization of the projected overspent escrow balance at December 31, 2015, over two years. The level for natural gas operations consists of the conservation budget of $4,411,207 less an escrow amortization adjustment of $1,130,748. The natural gas escrow adjustment represents the test-year amortization of the projected underspent escrow balance at December 31, 2015, over two years.

35. The reasonable level of expensed farm rewiring costs recoverable in rates for the 2016 test year is $710,171 for electric utility operations. The expense level consists of the farm rewiring budget of $1,000,000 less an escrow amortization adjustment of $289,829. The escrow adjustment represents the test-year amortization of the projected underspent escrow balance at December 31, 2015, over two years.

36. Commission staff's trend analysis used to forecast the test-year credit from ATC is reasonable.

37. It is reasonable to exclude $1.4 million of strategic services from the test-year revenue requirement.

38. WPSC's use of a 4-year average to forecast test-year injuries and damages is reasonable.

39. It is reasonable to exclude $3.7 million in active medical expense from test-year revenue requirement.

40. It is not reasonable to include in revenue requirement the cost of the non-qualified pension for the 13 executives who received change-in-control terminations in 2015.

41. It is not reasonable to include in the revenue requirement the cost of the Integrys Board of Directors.

42. It is reasonable to restore the inadvertent disallowance of half of the Electric Power Research Institute dues.

43. It is not reasonable to reduce WPSC's revenue requirement by $271,601 to remove the costs associated with the ICE project that will now be allocated to WPSC due to the sale of Upper Peninsula Power Company (UPPCo).

44. It is reasonable to continue using the average of the IHS Economic – Global Insight and the Blue Chip Economic Indicators CPI indices to forecast the level of inflation for 2015 and 2016.

45. It is not reasonable to adjust revenue requirement to correct an alleged error in Commission staff's calculation of Federal Insurance Contributions Act (FICA) expense.

46. It is reasonable not to include any costs related to the Fox Unit 3 project in test-year revenue requirement.

47. It is reasonable to exclude costs associated with the estimated $70 million in cost overruns related to the ReACT™ project.

48. It is reasonable to authorize WPSC to defer the incremental revenue requirement associated with estimated cost overruns associated with the ReACT™ project through 2016.

49. It is not reasonable to put in place an earnings sharing mechanism similar to what Wisconsin Electric Power Company (WEPCO) and Wisconsin Gas Company (WGC) have in place as directed by the Commission's Final Decision in docket 9400-YO-100 dated May 21, 2015.

50. It is reasonable to include in revenue requirement an additional adjustment reducing payroll by $11.3 million.

51. It is reasonable to decrease net plant in service to reflect the fact that WPSC has historically forecasted its construction expenditures to go into service faster than they actually have. It is also reasonable to include the additional Allowance for Funds Used During Construction (AFUDC), and to exclude the tax effect of the debt portion of the additional AFUDC.

52. It is reasonable to include, as discussed in the Opinion section in this Final Decision, updated information respecting WPSC pension and benefit costs, and to adopt all miscellaneous uncontested adjustments and corrections for the calculation of the revenue requirement.

53. A long-term range of 49 percent to 54 percent for WPSC's common equity ratio, on a financial basis, is reasonable and provides adequate financial flexibility.

54. An appropriate target level for the test-year average common equity measured on a financial capital structure basis is 51 percent.

55. It is appropriate to limit the amount of equity infusion to the lesser of the amount needed to achieve a test-year average equity ratio, on a financial basis, approximating the target level of 51 percent or the amount found not to result in cash or cash equivalent holdings.

56. A reasonable estimate of the amount of debt equivalent to be imputed into WPSC's financial capital structure for the test-year is $21,131,385, consisting of: (a) no debt imputation for advances from affiliated companies, affiliated capital leases, purchased power capital leases, wind-related purchased power agreements guarantees, underfunded pension and other post-retirement employee benefit plans, and asset retirement obligations; (b) $491,283 related to non-purchased power agreement operating leases; (c) $20,049,234 related to purchased power operating leases; and (d) $219,024 related to wind-related land leases. An

additional $1,051,000 related to debt of subsidiary is also included in WPSC's financial capital structure.

57. A reasonable financial capital structure for the test year consists of 51.00 percent common equity, 1.74 percent preferred stock, 44.07 percent long-term debt, 2.44 percent short-term debt, and 0.76 percent debt equivalence for off-balance sheet obligations, including subsidiary debt.

58. It is reasonable to revise WPSC's dividend restriction based on the capital structure determinations in this proceeding, and to revise the wording to match the wording of WEPCO and WGC's dividend restrictions, as set forth in the Opinion section in this Final Decision.

59. It is reasonable to require WPSC to submit a 10-year financial forecast in its next rate proceeding.

60. It is reasonable to require WPSC to submit in its next rate proceeding detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent.

61. A reasonable utility capital structure for ratemaking for the test year consists of 50.47 percent common equity, 1.78 percent preferred stock, 45.25 percent long-term debt, and 2.50 percent short-term debt.

62. A reasonable return on utility common stock equity is 10.00 percent.

63. A reasonable interest rate for short-term borrowing through commercial paper is 1.20 percent for the test year.

64. A reasonable interest rate for the $250 million long-term debt to be issued in 2015 is 4.20 percent.

65. A reasonable average embedded cost for long-term debt is 4.65 percent for the test year.

66. A reasonable average cost for preferred stock is 6.08 percent for the test year.

67. A reasonable weighted average composite cost of capital is 7.29 percent.

68. It is not reasonable to incorporate an additional adjustment to the return on equity to reflect higher levels of fixed charges.

69. It is reasonable to consider the full range of cost-of-service study (COSS) results presented in the record when allocating test year 2016 electric and natural gas revenue responsibility.

70. It is reasonable to consider the setting of fixed charges as a policy decision, and to consider state and Commission policies, fairness, and economic efficiency over the short and long term when setting fixed charge rates for residential and small commercial customers.

71. It is reasonable to authorize a gradual increase in existing customer charges resulting in charges of $21.00 per month for residential customers, $27.63 per month for single-phase small commercial customers, and $44.21 per month for three-phase small commercial customers.

72. It is reasonable to approve an increase of 5 percent for the system demand charges for the Cg-20 rate class, with a corresponding decrease in energy charges.

73. It is reasonable to maintain rates at current levels for the Cp rate class, as adjusted for final revenue requirement.

74. It is reasonable to maintain the current interruptible credits at the current amounts.

75. It is reasonable to approve changes, as discussed in the Opinion section of this Final Decision, to the Real Time Market Pricing tariff.

76. It is not reasonable to require WPSC to modify its reporting of behind-the-meter generation.

77. It is not reasonable to require WPSC to include a transmission credit in its PG-2A and PG-2B tariffs.

78. It is reasonable to approve rate changes for electric and natural gas service as shown in Appendices B and C.

Conclusions of Law

The Commission concludes it has jurisdiction under Wis. Stat. §§ 1.12, 196.02, 196.025, 196.03, 196.19, 196.20, 196.21, 196.37, 196.374, 196.395, and 196.40 and Wis. Admin. Code chs. PSC 113, 116, and 134 to issue a Final Decision authorizing WPSC to place in effect the rates and rules for electric and natural gas utility service set forth in Appendices B and C, subject to the conditions specified in this Final Decision. The rates and rules for electric and natural gas utility service in Appendices B and C are reasonable and appropriate as a matter of law.

Opinion

Applicant and its Business

WPSC is a public utility, as defined in Wis. Stat. § 196.01(5), engaged in the production, transmission, distribution, and sale of electricity, and in the purchase, distribution, and sale of natural gas in a service area of approximately 11,000 square miles in north-central and northeastern Wisconsin and adjacent parts of upper Michigan. Cities that WPSC serves with retail electric service or natural gas service include Green Bay, Marinette, Oshkosh, Rhinelander, Sheboygan, Stevens Point, and Wausau in Wisconsin, and Menominee in Michigan.

WPSC also sells electricity at wholesale rates to other utilities and electric cooperatives for resale. FERC regulates wholesale sales and rates. WPSC's wholesale rates, therefore, are not affected by this Final Decision. Similarly, the rates applicable to retail sales of electricity and natural gas to Michigan customers are not subject to the jurisdiction of this Commission and are not affected by this Final Decision.

At the time that this application was filed, WPSC was a utility affiliate and subsidiary of Integrys, which was a utility holding company headquartered in Chicago, Illinois. In June 2015, Wisconsin Energy Corporation acquired Integrys Energy Group, Inc., forming a new utility holding company, WEC Energy Group, headquartered in Milwaukee, Wisconsin. Integrys remains a second-tier holding company within WEC Energy Group. The Commission approved this acquisition on May 21, 2015, in docket 9400-YO-100.[2]

Revenue Requirement

Fuel Costs

Wisconsin Admin. Code ch. PSC 116 (Fuel Rules) establishes the rate recovery procedures for monitored fuel costs, and requires the Commission to approve a fuel cost plan. In addition to the monitored fuel costs, there are also other fuel costs that are not subject to Fuel Rules monitoring, but are reasonable for inclusion in the revenue requirement in a general rate proceeding. The Commission finds that a reasonable estimate of total company fuel costs (all fuel costs) for the test year is $534.4 million. The Commission finds that a reasonable 2016 fuel cost plan level of monitored fuel costs is $368,042,000 which reflects the costs of generation and purchased energy, minus revenue from opportunity sales of energy and capacity. The reasonable

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[2] *Application of Wisconsin Energy Corporation for Approval to Acquire the Outstanding Common Stock of Integrys Energy Group, Inc.*, docket 9400-YO-100, Final Decision (Wis. PSC May 21, 2105) (PSC REF#: 236761).

2016 fuel cost plan also reflects the decreased margin on natural gas used for electric generation, purchased from WPSC's own gas utility. The 2016 fuel cost plan monitored fuel costs divided by the authorized level of native requirements of 13,900,713 MWh results in an average net monitored fuel cost per MWh of $26.48.

It is reasonable to monitor WPSC's fuel costs, using a plus or minus 2 percent bandwidth, as provided in Wis. Admin. Code § PSC 116.06(3).

The fuel cost data in Appendix D shall be used for monitoring WPSC's 2016 fuel costs.

Purchased Power Agreement Entered into After Commission Staff's Audit

WPSC requested that any changes resulting from new or revised purchased power agreements (PPA) that were executed after Commission staff's audit, but prior to or coincident with the delayed exhibit for the update of commodities prices based on the New York Mercantile Exchange (NYMEX), be incorporated into the final revenue requirement. WPSC entered into two such PPAs and provided the price and energy purchases, in megawatt-hours, associated with the PPAs and the corresponding impact on fuel costs in a delayed exhibit. Upon review, neither Commission staff nor any party objected to the inclusion of these updates in the revenue requirement. As a result, the Commission finds that it is reasonable to incorporate these PPAs in the authorized revenue requirement.

Deferral of Rail Obligation Costs

WPSC proposed continuing the deferral of its rail obligation (tonnage) costs incurred for the period January 1, 2014, through December 31, 2015. These deferred costs reflect its obligations for coal delivery under its origin rail contract. In WPSC's most recent rate case proceedings in docket 6690-UR-122, and again in docket 6690-UR-123,[3] the Commission ordered that the rail obligation be deferred until after the end of the contract on December 31, 2015.

The Wisconsin Industrial Energy Group (WIEG) and Citizens Utility Board (CUB) stated in the prior dockets and in the current proceeding that the rail obligation would not be known, nor would it come due until the end of the contract, therefore such costs should continue to be deferred until the end of the contract. Both WIEG and CUB agreed that it is reasonable to continue deferring the costs until after the end of the contract when any rail obligation costs will be known. WPSC agreed that the deferral should continue until such time as any minimum rail obligation costs are finalized.

Consistent with the Commission's previous decisions in dockets 6690-UR-122 and 6690-UR-123, the Commission finds it reasonable to defer any additional rail obligation costs for the 2015 test year until after the end of the contract. Once the contracts are finalized and the actual rail obligation costs are known, WPSC shall identify these amounts in the next applicable fuel cost proceeding.

Escrow of Transmission Costs

Consistent with the Commission's Final Decision in docket 6690-UR-123, WPSC requested continued escrow treatment for network transmission charges and credits from ATC and MISO. WPSC noted that these are significant expenses with considerable uncertainty. Commission staff agreed that escrow treatment would be appropriate given that there is

[3] *Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, docket 6690-UR-122, Final Decision (Wis. PSC Dec. 18, 2013) (PSC REF#: 194645); *Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, docket 6690-UR-123, Final Decision (Wis. PSC Dec. 18, 2014) (PSC REF#: 226374).

continued uncertainty surrounding these costs, including potentially large refunds that may be ordered by FERC in 2016 related to transmission company rate of return and MISO's SSR tariff.[4]

The Commission finds it reasonable to allow WPSC to escrow network transmission service charges and credits, including any FERC-ordered retroactive refunds in ATC and MISO, through December 31, 2016. This is consistent with how the Commission has treated these costs for other utilities in recent decisions. Nonetheless, the Commission does not intend to establish a permanent escrow for these costs, and it will make a determination to allow escrowing on a case-by-case basis.

ReACT™ Guaranteed Performance Contract and Startup Costs

On April 12, 2013, in docket 6690-CE-197, the Commission authorized WPSC to construct, install, and place in operation a new multi-pollutant control technology known as ReACT™, as part of WPSC's Weston Generating Station Unit 3 (Weston 3) in Marathon County, Wisconsin, at an estimated cost of $275 million.[5] WPSC is constructing the facilities to meet the requirements of a Consent Decree agreed to between WPSC and the U.S. Environmental Protection Agency (EPA) that resulted from allegations by EPA of Clean Air Act violations at WPSC's Weston and Pulliam Generating Stations. WPSC also proposes to use the new facilities to comply with future air pollution regulations and help maintain a balanced generation portfolio. On September 20, 2013, WPSC informed the Commission that

[4] FERC dockets EL 14-12 and EL 15-45 relative to rate of return and dockets EL 14-34, ER 14-1242, ER 14-1243, ER 14-2860, ER 14-2862, ER 14-2952 and all related sub-dockets, relative to the MISO SSR tariff.
[5] *Application of Wisconsin Public Service Corporation for Authority to Construct and Place in Operation a New Multi-Pollution Control Technology System for Unit 3 of the Weston Generating Station, Marathon County, Wisconsin*, docket 6690-CE-197, Final Decision (Wis. PSC Apr. 3, 2013) (PSC REF#: 183440).

the final estimated costs of the project would exceed the 5 percent cost collar established in the Commission's Final Decision and Order in docket 6690-CE-197.

After its application was filed, WPSC requested that Commission staff include an adjustment to its 2016 fuel forecast to reflect uneconomic dispatch costs for Weston 3 during the initial start-up period of the ReACT™ system. WPSC's contract with its vendor includes a 12-month warranty period for operation of the system at Minimum Performance Standards, as well as a liquated damages remedy for failure to meet more strict Guaranteed Performance Standards (GPS). In order to invoke the GPS, WPSC must ensure that ReACT™ processes 18.8 million pounds of sulfur dioxide (SO_2) within 15 months of the in-service date in order to properly season the ReACT™ activated coke pellet bed. WPSC intends to operate Weston 3 in a manner such that it will process the required 18.8 million pounds of SO_2 within 12 months of the in-service date, which is the same as the warranty period.

WPSC's approach will require Weston 3 to run at a high capacity factor during the initial 12-month period, which means that it will frequently be dispatched uneconomically. This will result in additional monitored fuel costs. WPSC argued that these costs are reasonable since it benefits both WPSC and ratepayers to invoke the GPS within the first 12 months because this is concurrent with the warranty period. WPSC claimed that completing the GPS testing after the warranty period presents additional risks to ratepayers.

Both WIEG and CUB urged the Commission to exclude from the revenue requirement the uneconomic costs of associated with the testing and seasoning of ReACT™. CUB argued that the uneconomic dispatch is really not a technical requirement of ReACT™, and therefore the resulting costs should have been avoided by WPSC at the time it negotiated the ReACT™ contract. WIEG argued that WPSC should have recognized at the time of contracting that it would be unable to properly test the system to ensure application of the contract's warranty provisions without dispatching Weston 3 uneconomically. The Wisconsin Paper Council (WPC) supported WIEG's position.

Commission staff noted that the uneconomic dispatch costs were not included in WPSC's initial 2016 test-year rate filing, and WPSC did not notify Commission staff of these costs until near the completion of its audit. Commission staff further noted that WPSC's application to construct ReACT™ indicated that it would be necessary to run Weston 3 uneconomically for only approximately 6 months during the initial ReACT™ startup. Despite the fact that WPSC has been providing the Commission with quarterly reports on the progress of the ReACT™ project, WPSC failed to notify the Commission of the increased length of time required to invoke the GPS provisions in the contract until near the conclusion of the audit process in this rate case.

WPSC's failure to disclose the extension of the time period during which Weston 3 may be required to dispatch uneconomically impacted the Commission's ability to assess the reasons and need for the extension. While the Commission does not believe that entering into the GPS contract was imprudent, WPSC should have notified the Commission of the changes necessary to meet the GPS requirements sooner. Further, the Commission agrees with the parties that it is in the interest of both WPSC and its ratepayers to ensure that WPSC is able to invoke the GPS provisions in its contract. As a result, it is reasonable to allow WPSC to recover the costs associated with the uneconomic dispatch of Weston 3 during the first 6 months of its startup period, which is consistent with WPSC's initial application for approval of the ReACT™

project.[6] Furthermore, the Commission finds it reasonable to require WPSC to identify and remove from monitored fuel costs any such costs incurred after the first 6 months and that these costs be borne solely by the WPSC shareholders.

The ReACT™ contract contains numerous provisions for WPSC to recover liquidated damages from its vendor in the event of missed milestones or failure to meet contractual performance standards. Because these liquidated damages could be significant, and because of the large cost overruns already experienced in this project, the Commission finds that it is reasonable to require WPSC to file a report quarterly with the Commission that identifies: (1) any liquidated damages that were received; (2) any claims that are being pursued; and (3) any potential claims that were not pursued, including an explanation as to why damages were not pursued. WPSC agreed that any liquidated damages received should be deferred and returned to ratepayers, provided that such a deferral is net of any costs to obtain the liquidated damages, such as uneconomic dispatch costs. At this time, it is premature to consider liquidated damages since the process for seeking and recovering damages is lengthy and will not be completed during the 2016 test year. Therefore, the Commission declines to make a determination on how liquated damages obtained under the ReACT™ contract, if any, should be treated for ratemaking purposes.

Finally, WPSC requested that it be allowed to capitalize the costs of the coke and ammonia consumed during the Minimum Performance Standard (MPS) testing of the ReACT™

[6] The Commission notes that disallowance of recovery of a portion of the uneconomic dispatch costs is similar to the disallowance of costs relative to the Bent Tree Wind Farm in Wisconsin Power and Light Company's 2010 rate case decision. *See Application of Wisconsin Power & Light Co. for Authority to Adjust Its Electric and Natural Gas Rates*, docket 6680-UR-117, Final Decision (Wis. PSC Dec. 8, 2010) (partial disallowance of construction costs was reasonable due to the failure of WP&L to disclose relevant information regarding transmission line constraints that significantly hampered movement of power from the wind farm) (PSC REF#: 142283).

system, which will occur before the ReACT™ equipment is placed into service. WPSC had incorrectly identified such costs as monitored fuel costs in its initial application. The Commission finds that capitalization of these costs is consistent with the proper accounting treatment and directs WPSC to capitalize any such costs incurred during MPS testing.

NYMEX and Other Updates

Consistent with past Commission practice, WPSC requested permission to update its 2016 fuel plan to reflect updated commodities (coal and natural gas) price forecasts, rail costs, purchased power costs, purchased capacity costs, risk management costs, opportunity sales revenues and interruptible revenue credits. WPSC also requested that actual October ATC transmission expense true-ups be included as part of the transmission expense update. WPSC filed a revised delayed exhibit based on NYMEX futures costs as of November 4, 2015. It is reasonable to update the 2016 fuel plan and costs to reflect the actual October true-ups in the transmission expense and the information contained in WPSC's delayed exhibit. (Ex.-WPSC-Guntlisbergen-3r; PSC REF #: 278401.)

Miscellaneous Fuel Cost Items

WPSC requested an adjustment to its monitored fuel costs to reflect the Commission's decision in docket 6690-DR-109,[7] which authorized WPSC to self-supply station power for the Fox Energy Center. At the time this rate case application was filed, WPSC was receiving service at the Fox Energy Center from Kaukauna Utilities. The Commission finds it reasonable

[7] *Petition of Wisconsin Public Service Corporation for Declaratory Ruling Regarding the Right to Self-Supply Station Power to Fox Energy Center*, docket 6690-UR-109, Final Decision (Wis. PSC Sept. 25, 2014) (PSC REF#: 218963), affirmed by *City of Kaukauna v. Pub. Serv. Comm'n*, Case No. 14-CV-1084, Decision and Order, (Cir. Ct. Outagamie County May 4, 2015), appeal pending, *City of Kaukauna v. Pub. Serv. Comm'n*, Appeal No. 15-AP-1182.

to accept WPSC's proposed increase in test-year fuel costs to account for WPSC's self-supplying the Fox Energy Center.

CUB identified three additional items related to WPSC's 2016 monitored fuel costs for the Commission's consideration. These included: (1) requiring WPSC to use the most-recently available 12 months of LMP data for the Crane Creek Wind Farm generator node; (2) requiring that all PPAs finalized during or after the Commission staff audit be subject to further staff review before being included in the fuel plan; and (3) requiring that WPSC take reasonable steps to ensure that any refund received from ATC as a result of the pending return on equity docket before FERC in dockets EL 14-12 and EL 15-45, be returned to customers as soon as possible. The Commission notes that this Final Decision addresses these concerns and that no specific conditions are necessary. WPSC used the most recent 12 months of LMP data for Crane Creek, and Commission staff reviewed the PPAs included in the November 25, 2015, delayed exhibit. Finally, the Commission notes that the potential refunds in question are to be included in the existing escrow of transmission system costs and will be addressed in WPSC's next fuel or rate case proceeding.

Electric and Natural Gas Sales Forecasts

WPSC used weather-normalized historical electrical and natural gas sales data to form the basis of its sales forecast. However, in this proceeding, as in previous cases, WPSC declined to provide that data to Commission staff, citing an order point from the Commission's Final Decision in docket 6690-UR-116, dated December 21, 2004.[8]

[8] *Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, docket 6690-UR-116, Final Decision (Wis. PSC Dec. 21, 2004) (PSC REF#: 25848).

Commission staff proposed several adjustments to electric and natural gas sales forecasts based upon Commission staff's long-standing methods for forecasting. Because the weather-normalized data used by WPSC were not made available, it was difficult to determine why WPSC's forecast of electric and natural gas sales differed from the Commission staff's forecast. The Commission recognizes that forecasting sales can be somewhat subjective and require judgement in evaluating historical trends. In order to assist the Commission's ability to assess the reasonableness of WPSC's sales forecast, the Commission finds it reasonable to require that WPSC provide its weather-normalized historical electric and natural gas sales on a rate schedule basis in future rate proceedings.

In addition, in this proceeding, WPSC submitted rebuttal testimony that included partial year, unaudited 2015 sales data for both electric and natural gas sales to support its as-filed forecasts and to justify reducing its filed forecast for some rate schedules. This 2015 data was not provided to Commission staff during its audit, but instead was provided more than a month after the audit had been finalized. The Commission recognizes that changes occur during and after a rate case audit. Additional information received after the completion of Commission staff's audit may be relevant to the Commission in its decision-making where there are compelling and unusual circumstances.[9] However, the utility has the burden of demonstrating that the evidence is unusual and compelling because it has knowledge of the information.

In this instance, the Commission finds that it is not reasonable to consider the 2015 sales information in determining the test-year forecast of electric and natural gas sales because this data was provided too late in the process to be verified by Commission staff. Moreover, the late

[9] The Commission's audit policy for late information was first established in its order dated December 29, 1988, in Wisconsin Electric Power Company docket 6630-UR-102.

information, in the Commission's experience and expertise, is neither compelling nor unusual when considered in light of previous rate cases of WPSC and other investor-owned utilities. Accordingly, in the Commission's decisions on the various sales forecast issues which follow, the Commission declines to consider partial year, unaudited 2015 sales data.

Rg-1 Electric Sales

WPSC, in direct testimony, presented an Rg-1 forecasted use per customer of 7,098 kWh for the 2016 test year. Subsequently, in rebuttal testimony, WPSC offered an Rg-1 forecasted use per customer of 6,950 kWh for the test year. Commission staff increased the use per customer and increased the fixed charge counts for this rate schedule. Fixed charge counts represent the number of bills for this class in the test year (essentially, the average number of customers multiplied by 12). Commission staff estimated the use per customer using an average of its revised 2012 and 2014 weather-normalized use per fixed charge count, which resulted in average annual sales of 7,109 kWh per fixed charge count. Commission staff calculated the 4-year compound average growth rate (CAGR) in fixed charge counts for the period 2010 through 2014 using actual counts, resulting in a rate of 0.42 percent per annum. Commission staff then used this annual growth rate to project fixed charge counts based on the 2014 actuals to the 2016 test year to arrive at 371,571 fixed charge counts, an increase of 3,641 from WPSC's forecast. WPSC disagreed with Commission staff's methodology for forecasting the use per fixed charge count, but did not dispute the fixed charge count. The Commission finds Commission staff's revised forecast of 2,641,483,407 kWh for the Rg-1 rate schedule to be reasonable because it is reasonable to forecast the test year use per customer by using the average of 2012 and 2014 weather-normalized use per customer, and it is reasonable to use the 4-year CAGR to forecast the test year average fixed charges for the Rg-1 rate schedule.

Chairperson Nowak dissents.

Cg-20 200-500 URB Electric Sales

WPSC, in direct testimony, presented a Cg-20 URB 200-500 fixed charge count of 2,890 for the 2016 test year. In rebuttal testimony, WPSC offered an amended forecast of 3,115 fixed charge counts for the test year. In direct testimony, WPSC presented a Cg-20 URB 200-500 forecast of 1,858,866,512 kWh and then presented a forecast of 1,954,510,679 kWh in rebuttal testimony, both for the 2016 test year. Commission staff increased the number of fixed charge counts and accepted the WPSC's forecasted use per fixed charge count. Commission staff calculated its 2016 test-year forecast for fixed charge counts by calculating the historical CAGR of 2.88 percent based on actual counts for the period 2010 through 2014. This percentage was used to project continued growth in fixed charge counts from the 2014 year to the test year. Commission staff's estimate of fixed charge counts of 3,140 per year resulted in an increase of 250 fixed charge counts over WPSC's filed forecast. WPSC disagreed with Commission staff's fixed charge count forecast, claiming it was too high. The Commission finds Commission staff's test-year estimate of 2,022,508,741 kWh for the Cg-20 200-500 URB rate schedule to be reasonable because it is based on the growth in fixed charge counts over the most recent five years through 2014.

Chairperson Nowak dissents.

Rg-3 Gas Sales

WPSC filed its 2016 test year forecast for Rg-3 of 235,886,029 therms in direct testimony. WPSC's forecasted test-year residential gas sales were based on a use per customer of 820 therms, which WPSC stated is close to the 3-year average. Commission staff noted that weather-normalized use per customer has been increasing every year since 2012, and used the most recent actual (2014) weather-normalized use per customer of 843 therms, for a total test-year forecast of 242,470,845 therms. The Commission finds Commission staff's forecast of 242,470,845 therms for the RG-3 rate schedule to be reasonable given that historical weather-normalized use per customer has increased every year since 2012 and because the forecast is based upon the most recent actual weather-normalized use per customer.

Chairperson Nowak dissents.

Cg-FS Gas Sales

WPSC's original 2016 test year forecast for Cg-FS consisted of 76,455,619 therms and 10,191 fixed charge counts. In rebuttal testimony, WPSC offered an amended forecast of 68,500,000 therms. Commission staff increased the fixed charge count and decreased the use per customer for this rate schedule compared to WPSC's filed levels. In rebuttal testimony, WPSC agreed with Commission staff's increase in fixed charge counts, but argued that Commission staff's use per customer should be decreased further. Commission staff noted that Commission staff's actual weather-normalized sales for this rate schedule have shown an increasing trend since 2010, and as a result, Commission staff used the most recent two-year average (2013-2014) weather-normalized use per customer, for a total test-year forecast of 80,366,168 therms. The Commission finds Commission staff's forecast of 80,366,168 therms for the Cg-FS rate schedule to be reasonable given the increasing trend since 2010.

Cg-FM Gas Sales

WPSC's original 2016 test year forecast for Cg-FM consisted of 50,233,705 therms and 837 fixed charge counts. In rebuttal testimony, WPSC offered an amended forecast of 1,398 fixed charge counts. Commission staff increased the fixed charge count and decreased use per customer for this rate schedule. In rebuttal testimony, WPSC challenged both changes, arguing that Commission staff's fixed charge count should be increased by an additional 150 customers, and that Commission staff's total sales forecast for this rate schedule was too high. The Commission finds Commission staff's forecast of 56,291,620 therms and fixed charge counts of 1,248 for the Cg-FM rate schedule to be reasonable because it is based on its increased fixed charge count of 1,248, and the most recent 2-year average (2013-2014) weather-normalized use per customer.

CG-TSL-IG2T

WPSC's original 2016 test year forecast for Cg-TSL-IG2T consisted of 211,448,744 therms. In rebuttal testimony, WPSC offered two alternative forecasts of 174,174,881 therms or 165,808,241 therms. Commission staff increased WPSC's forecast for the CG-TSL-IG2T rate schedule by 33.2 million therms. This included an adjustment to reflect an additional 19.5 million therms from customers that formerly took service under the Coal Displacement Gas Transportation tariff, which was closed in the Commission's Final Decision in docket 6690-UR-123, plus an additional 13.7 million therms for growth. WPSC disagreed with Commission staff's methodology for determining the growth rate and argued that some of the growth was double counted. The Commission finds it reasonable to increase the forecast to reflect an additional 19,500,000 therms associated with the closure of the Coal Displacement Gas Transportation tariff to WPSC's filed forecast, but it is not reasonable to forecast an additional 13.7 million therms because the historical data does not support changes of this magnitude. A reasonable test-year forecast is 230,948,744 therms for the CG-TSL-IG2T rate schedule.

2015 Wage Increase

The payroll expense forecast is derived by starting with an actual payroll level and forecasting changes in wages and employee counts to get to the test-year payroll level. In this proceeding, Commission staff applied the forecasted inflation rates of 0.0 percent for 2015 and 2.1 percent for 2016 to estimate the wage increases for non-represented employees. Commission staff used the actual wage increases in those years for represented employees. WPSC disagreed with this approach, stating that the actual wage increase granted to its non-union employees in 2015 was 2.6 percent. In the past, the Commission has sometimes used inflation to forecast the bridge year non-union wage increase and has sometimes used the actual non-union wage increase for that period. In this proceeding, the Commission finds it reasonable to use 1.3 percent for the 2015 wage increase in the calculation of test-year payroll expense. This represents a compromise between the past Commission practices of using inflation and actual wage increases.

Change-in-Control Terminations

Commission staff removed from test year revenue requirement the cost of 13 executives who received change-in-control terminations in 2015 resulting from WEC Energy Group's recent acquisition of Integrys. WPSC stated that costs will be allocated to WPSC for the senior executives of WEC Energy Group and that the costs associated with the 13 executives is a reasonable estimate of the costs that will be allocated to WPSC from the WEC Energy Group. Commission staff argued that the cost of WEC Energy Group's senior staff is already being fully recovered by WEPCO and WGC ratepayers and that including an allocated portion of the cost of senior staff in WPSC's revenue requirement would result in a portion of these costs being recovered from ratepayers twice. The Commission finds that the evidence in the record was not sufficient to justify including the cost of the 13 executives in the test-year revenue requirement.

Incentive Compensation

Commission staff reduced WPSC's filed payroll level by $10.6 million (or $8.1 million charged to current operations) to remove the cost of incentive compensation consistent with the Commission's decision on this issue in WPSC's last rate case, docket 6690-UR-123. WPSC stated that the plan is substantially the same as the 2015 plan and is based on performance metrics designed to incentivize employees to meet goals that will create benefits for customers. WPSC further stated that the total compensation level it was proposing for the test year, including incentive compensation, provides a competitive market-based level of total compensation. The Commission again finds that it is not reasonable to include the cost of incentive compensation in test-year revenue requirement. WPSC did not perform a new compensation study since the last rate case proceeding, where the Commission determined that WPSC's compensation, without inclusion of incentive compensation, is slightly above market.

For the reasons discussed above, the Commission also finds that it is not reasonable to include the cost of incentive compensation for employees located at the Columbia and Edgewater generating stations in test-year revenue requirement.

Storm Damage

In this proceeding, Commission staff forecasted the test-year storm damage expense using the most recent 3-year average of such costs. WPSC disagreed with Commission staff's forecast, stating that using the most recent 4-year average would be more reasonable because of the variability in the cost for this activity. The Commission finds that Commission staff consistently uses a 3-year average to forecast such items, and it is reasonable to use the most recent 3-year average to forecast test-year storm damage expense.

Uncollectible Accounts Expense

Commission staff forecasted the normal test-year level of uncollectible accounts expense using the historical ratio of net write-offs to sales revenue and applying that ratio to Commission staff's estimated test-year sales revenue. Commission staff then reduced that level by 25 percent to reflect the implementation of the ICE project that is, in part, a new customer billing system. As part of the implementation process, there will be three delays in the collection process that are expected to total at least 81 days, which is nearly 25 percent of the year. WPSC disagreed with reducing uncollectible accounts expense to reflect these delays, stating that the delays will either take place outside of the test year or will occur during the winter moratorium. The Commission finds WPSC's arguments to be persuasive and the evidence of potential delays in the collection process to be too speculative. Therefore, the Commission finds that it is not reasonable to reduce the test-year level of uncollectible accounts expense to reflect the implementation of ICE.

Energy Efficiency

Customer Service Conservation

WPSC's proposed 2016 electric and natural gas customer service conservation (CSC) activities support energy efficiency awareness through a variety of approaches including seasonal advertising campaigns, bill inserts, targeted newsletters, sponsorship of training events, participation in conferences and trade shows, research of energy efficiency topics, support for the specialized energy needs of low-income ratepayers and farmers, and financial support of the K-12 Energy Education Program.

In its Order in docket 5-BU-102, dated July 13, 2012, the Commission provided guidance regarding appropriate CSC activities. The Commission defined CSC activities as "those activities and services that a utility provides its customers to: (1) help them understand and control their energy use and bills; (2) create customer awareness of energy efficiency and its value; (3) provide information and assistance related to energy efficiency topics; or (4) encourage and assist customers to take advantage of other services provided by Focus on Energy and federal and state energy programs." Based on this guidance, the Commission finds WPSC's proposed 2016 CSC activities to be appropriate.

Conservation Budget and Escrow Adjustment

WPSC's filing included a proposed 2016 conservation budget of $20,658,817, which is comprised of payments of $18,081,428 to the Statewide Energy Efficiency and Renewables Administration, Inc. (SEERA), and $2,577,389 of other conservation expenditures. During Commission staff's audit, the budget for other conservation expenditures was reduced to $2,376,000 and that change was reflected in Commission staff's estimate of test-year revenue requirement. In addition, WPSC estimated that it would have an overspent balance of $599,805 at December 31, 2015, for electric operations and an underspent balance of $2,261,496 at December 31, 2015, for natural gas operations. The final revenue requirement upon which rates are based for the 2016 test year includes an amortization of the estimated overspent and underspent balances over two years beginning in 2016.

The reasonable level of expensed conservation costs recoverable in rates for the 2016 test year is $16,346,123 for electric operations and $3,280,459 for natural gas operations. The level for electric utility operations consists of forecasted conservation expenditures of $16,046,221 plus the amortization of the overspent amount of $299,902. The level for natural gas operations consists of forecasted conservation expenditures of $4,411,207 less the amortization of the underspent amount of $1,130,748. It is reasonable to direct WPSC to record these expense amounts annually until they are superseded by a Commission order authorizing new conservation escrow accruals.

Farm Rewiring Budget and Escrow Adjustment

WPSC's filing included a proposed 2016 farm rewiring budget of $1,000,000. WPSC estimated that it would have an underspent balance of $579,657 at December 31, 2015. The final revenue requirement upon which rates are based for the 2016 test year includes an amortization of the estimated underspent balance over two years beginning in 2016. The reasonable level of farm rewiring escrow expense recoverable in rates for the 2016 test year is $710,171, which is comprised of $1,000,000 of estimated farm rewiring expenditures less the amortization of the underspent amount of $289,829. It is reasonable to direct WPSC to record these expense amounts annually until they are superseded by a Commission order authorizing a new farm rewiring escrow accrual.

SEERA Credit

The final revenue requirement upon which rates are based for the 2016 test year includes a one-time credit of $1,395,879 to return the unspent amount of additional voluntary payments that WPSC made to SEERA. This amount is not included in WPSC's conservation escrow, and this credit will sunset on December 31, 2016. WPSC had agreed to make the additional payments as part of a settlement agreement with a number of parties in exchange for them not opposing WPSC's Revenue Stability Mechanism (RSM), also known as decoupling. The RSM credit was discontinued as of December 31, 2015.

ATC Credit

WPSC records a credit each year for the reimbursement from ATC for the services that WPSC performs for ATC. Commission staff used a trend analysis to forecast the credit from

ATC because the level of the credit has increased steadily from 2012 to 2014, and no other information indicated that the trend would not continue into the test year. WPSC disagreed with Commission staff's use of a trend analysis and believes it would be more reasonable to use a 3- or 4-year average of the historical credit amounts to forecast this item. The Commission finds it reasonable to use a trend analysis to forecast the test-year credit from ATC.

Commissioner Huebsch dissents.

Outside Services

Commission staff reduced WPSC's filed level of outside services expense by $1.4 million for certain strategic services because of the acquisition of Integrys by WEC Energy Group. The costs removed related to services that would normally be provided at the holding company level and for which the cost would be allocated among the operating companies such as employee benefits, compensation, talent management, and investor relations. WPSC disagreed with this adjustment, stating that WPSC would continue to receive such services from WEC Business Services and would be allocated a portion of the cost. Commission staff stated that the cost of such services is presumably already being recovered from the ratepayers of WEPCO and WGC and, if a portion of these costs was also authorized to be recovered from WPSC ratepayers, there is a potential for some of these costs to be recovered twice. The Commission finds that this issue is an example of synergy savings from the acquisition of Integrys by WEC Energy Group, and that WPSC did not demonstrate that these costs are not already being recovered by the ratepayers of WEPCO and WGC or otherwise present sufficient evidence demonstrating what a reasonable estimate of outside services expenses might be.

Injuries and Damages

In this proceeding, Commission staff reduced WPSC's filed estimate of injuries and damages expense to reflect the most recent 3-year average of such costs. WPSC disagreed with Commission staff's forecast, stating that using the most recent 4-year average would be more reasonable because of the variability in the costs for this activity. The Commission finds that it is reasonable to use the most recent 4-year average to forecast the test-year level of injuries and damages expense because of the wide variation in injury and damage claims each year.

Commissioner Montgomery dissents.

Active Medical Expense

Commission staff compared WPSC's filed estimate of active medical expense to the actual level for the last four rate proceedings (2009, 2011, 2013, and 2014) and found that WPSC forecasted an average annual amount of $3.7 million more than its actual active medical expense in those four test years. Based on this finding, Commission staff reduced WPSC's filed level of active medical expense by $3.7 million. WPSC disagreed with this adjustment and instead recommended that the Commission reduce the adjustment from $3.7 million to $1.1 million based on WPSC's actual expense levels in 2013, 2014, and the first 6 months of 2015. The Commission finds that it is reasonable to reduce WPSC's filed level of active medical expense by $3.7 million for the test year because the record clearly established that WPSC has consistently overestimated these expenses over the last three year.

Non-Qualified Pension Related to Change-in-Control Terminations

Commission staff removed the costs included in WPSC's filed revenue requirement for the salaries and associated benefits of the 13 executives who received change-in-control terminations in 2015. Those costs are prohibited from rate recovery per the Commission's Final Decision in docket 9400-YO-100, dated May 15, 2015. In addition, per the matching principle in accounting theory, costs are to be matched with their associated benefit. These executives will not be employed by WPSC in the 2016 test year, and the cost of their benefits should have been recognized during their employment. WPSC testified that, under Generally Accepted Accounting Principles, these costs would be recognized in the test year. WPSC further testified that these costs, along with the associated benefits, represent WPSC's allocated share of the salaries of WEC Energy Group executives. The Commission finds that this issue is similar to the strategic services issue; it is another example of synergy savings from the acquisition of Integrys by WEC Energy Group. WPSC did not demonstrate that these costs are not already being recovered by the ratepayers of WEPCO and WGC. It is not reasonable to include the cost of the non-qualified pension for the 13 executives who received change-in-control terminations in test-year revenue requirement.

Integrys Board of Directors Costs

Because of WEC Energy Group's acquisition of Integrys, Commission staff excluded the cost of the Integrys Board of Directors because it will no longer exist in the test year. WPSC argued it should recover this cost as it represents the cost that will be allocated to WPSC for the WEC Energy Group Board of Directors. Commission staff testified that Wisconsin Energy Corporation's board of directors costs are already being recovered in their entirety by the ratepayers of WEPCO and WGC until those companies apply for another change in rates. Commission staff argued that it would be duplicative to allow WPSC to recover its allocated cost for this item in the 2016 test year. The Commission finds that this issue is similar to the strategic services issue and the issue regarding the change-in-control terminations of 13 executives and that it is another example of synergy savings from the acquisition of Integrys by WEC Energy Group. Similarly, WPSC failed to present sufficient evidence demonstrating a reasonable estimate of what these costs might be. For these reasons, it is not reasonable to include the cost of the Integrys Board of Directors in test-year revenue requirement.

Electric Power Research Institute (EPRI) Dues

Commission staff inadvertently removed half of EPRI dues in its estimate of test-year revenue requirement. The Commission has historically allowed recovery of 100 percent of EPRI dues. In light of the historical treatment of EPRI dues, the Commission finds it reasonable to restore the inadvertently removed EPRI dues.

Allocation of ICE Project Costs to UPPCo

Order Condition 15 in the Commission's Final Decision in docket 9405-YI-100 (Order approving WPS Resources/People's Energy merger) states, "If, in the future, Integrys and/or any of its subsidiaries are down-sized in any significant way, the absolute cost allocation to WPSC shall not increase unless WPSC demonstrates that the cost allocation is just and reasonable." In this proceeding, CUB requested that any costs for the ICE project, potentially allocable to WPSC due to sale of UPPCo, be excluded from revenue requirement unless WPSC could show that the increased cost allocation is just and reasonable. WPSC argued the increase in the allocation of ICE costs to WPSC due to the sale of UPPCo is reasonable and that the benefits of ICE to WPSC continue to outweigh the costs. The Commission is persuaded by the testimony furnished by WPSC on this issue, and given the relatively small amount at issue ($271,061), the Commission finds that it is reasonable to allow recovery of the costs associated with the ICE project that would have been allocated to UPPCo. Further, such recovery is consistent with the

Commission's prior Order because WPSC has demonstrated to the Commission's satisfaction that the modest increase in costs to WPSC are just and reasonable.

Inflation Rates

In its filed test-year revenue requirement, WPSC forecasted certain expenses using a forecast of inflation for 2015 and 2016. Commission staff asked WPSC to identify the costs that were forecasted using an inflation forecast, and to identify the inflation factors used for the forecast period, which includes 2015 and 2016. WPSC used inflation factors of 2.3 and 2.7 percent for 2015 and 2016, respectively. Commission staff used inflation factors of 0.0 and 2.1 percent for 2015 and 2016, respectively. The Commission has consistently used the average of the IHS Economic – Global Insight and the Blue Chip Economic Indicators CPI indices to forecast the level of inflation for many years. In this proceeding, WPSC proposed using the July 2015 CPI forecast from Moody's Analytics to forecast inflation for 2015 and 2016. The Commission finds that WPSC did not present evidence as to why the long-standing use of the Commission's forecast of inflation should be changed and that it is reasonable to use the average of the IHS Economic – Global Insight and the Blue Chip Economic Indicators CPI indices to forecast the level of inflation.

FICA Tax

WPSC stated the Commission staff's calculation of test-year FICA expense was in error, but it did not identify the nature of the error. Commission staff used historical FICA expense from WPSC's annual report in calculating the test year estimate which was not refuted by WPSC. The Commission finds that there is not sufficient information on the record to conclude that

Commission staff's calculation of test-year FICA expense is in error. As a result, the Commission concludes that the revenue requirement should not be adjusted to correct the alleged error.

Timing of Plant Additions

In this proceeding, Commission staff reduced net plant in service to reflect that WPSC has historically forecasted its construction expenditures to go into service at a faster rate than has actually occurred. WPSC disagreed with Commission staff's adjustment because it believes the adjustment is based on faulty methodology. The Commission finds it reasonable to decrease net plant to reflect the fact that WPSC has historically forecasted its construction expenditures to go into service faster than they actually have. It is also reasonable to include the additional AFUDC associated with this adjustment, but it is not reasonable to also include the tax effect of the debt portion of the additional AFUDC because that issue was not discussed with Commission staff during its audit, and Commission staff was unable to determine the reasonableness of including it.

Commissioner Huebsch dissents.

Fox Unit 3

WPSC included approximately $61 million of Construction Work in Progress (CWIP) associated with the Fox Energy Center Unit 3 combined-cycle generating unit and assumed a 50 percent current return on CWIP in its filed revenue requirement. Subsequent to WPSC's filing in this docket, the Commission directed WPSC to withdraw its application for authority to construct this project in docket 9400-YO-100 as a condition of Commission approval of the acquisition of Integrys by WEC Energy Group. Removing the costs related to the Fox Unit 3 project reduces WPSC's test-year revenue requirement by approximately $3.5 million on a total company basis.

ReACT™ Cost Overruns

WPSC included in its filing the revenue requirement associated with its estimated cost of $345 million for its ReACT™ project. The Commission approved construction of this project with an authorized cost of $275 million in its Final Decision in docket 6690-CE-197, dated April 12, 2013. In this proceeding, Commission staff removed $70 million of plant in service related to the ReACT™ project so that no costs beyond the amount approved by the Commission are included in test-year revenue requirement. The Commission finds that until the project is placed in service, its final costs will be not be known, and it is premature for the Commission to consider recovery of any cost overruns. Removing the $70 million cost overrun for this project reduces the test-year revenue requirement by approximately $8.9 million on a total company basis.

WPSC did not disagree with the removal of the $70 million ReACT™ cost overrun as long as the Commission authorizes a deferral of the incremental revenue requirement associated with this disallowance, which would include the carrying cost of the plant not recovered at the weighted cost of capital and the related depreciation expense. The dispute on this issue related to the length of time of any authorized deferral. Commission staff noted that if a deferral was authorized beyond 2016 and WPSC did not file a rate case for the 2017 test year, then the Commission may not have an opportunity to identify additional synergy savings that are realized as a result of the acquisition of Integrys by WEC Energy Group.

As an alternative to specifying an end date for the deferral, it was suggested that the Commission could consider putting in place an earnings mechanism similar to what WEPCO and WGC have in place commencing in 2016 pursuant to the Commission's Final Decision in docket 9400-YO-100.

The Commission finds that it is reasonable to reduce the revenue requirement to reflect a $70 million reduction in the cost of ReACT™. The Commission also finds it reasonable to authorize WPSC to defer the incremental revenue requirement associated with the ReACT™ cost overrun, which would include the carrying cost of the plant not recovered at the weighted cost of capital and the related depreciation expense through December 31, 2016. It reasonable to address the appropriateness of recovery of the ReACT™ project cost overruns in a future proceeding.

As the Commission is not authorizing an open-ended deferral of these cost overruns, the Commission declines to impose an earnings sharing mechanism for WPSC at this time. The Commission notes that it has made several adjustments to the filed revenue requirement in this case to reflect synergy savings, and believes that additional savings, if any, can be addressed more appropriately in future rate cases.

Additional Payroll Adjustment

Commission staff identified additional payroll adjustments the Commission could make if it wanted to forecast additional merger savings in this proceeding. During Commission staff's audit, WEC Energy Group announced that it had named 70 senior leadership positions at the new company and that 58 of them were from the former Wisconsin Energy Corporation. Commission staff calculated the revenue requirement impact of assuming that the 58 counterpart positions from Integrys would be eliminated, less the 13 executives who had received change-in-control terminations. Eliminating 45 executives from Integrys Business Services (IBS) would reduce test-year payroll by approximately $2 million. Commission staff also calculated the revenue requirement impact of assuming that WPSC would hire no more employees after May 2015 and that employees as of May 2015 would continue to leave WPSC at the same rate they did from July 2014 through June 2015. The revenue requirement impact of removing these positions is approximately $9.3 million. Commission staff testified that these potential additional payroll adjustments would provide a range of $2 million to $11.3 million for the Commission if it wished to forecast a level of merger savings.

After the hearing, the Commission's Administrative Law Judge granted the request of Commission staff to supplement the record with additional evidence relevant to this issue. This additional evidence included two delayed exhibits, Ex.-PSC-Kettle-4 and Ex.-PSC-Kettle 5.[10] This information provided actual full-time equivalent (FTE) positions for WPSC and IBS through September 2015 and showed that in September 2015, the actual number of FTE positions was lower than that included in Commission staff's test-year payroll estimate by 25 WPSC FTEs and by 56 IBS FTEs (of which WPSC is allocated 38 percent). The additional information also included the revenue requirement impact of the layoff of 2 percent of staff that WEC Energy Group announced in late October 2015. This information demonstrated that WPSC would save approximately $8.5 million in 2016 as a result of those layoffs.

The Commission finds that the information in these delayed exhibits cannot be ignored and that this is one instance where acceptance of compelling new, easily verifiable factual information after Commission staff's audit had been finalized is appropriate. The two delayed exhibits relating to employee levels, taken together, support an additional reduction in test-year payroll expense. The Commission finds it reasonable to reduce test-year payroll expense by an additional $11.3 million to provide some synergy savings to ratepayers.

[10] *See* PSC REF#: 277857 and PSC REF#: 278069, respectively.

Miscellaneous Adjustments to Revenue Requirement

Consistent with current practice in the last several WPSC rate cases, the Commission finds that it is reasonable for WPSC to provide, prior to Commission decision, an update of its pension and benefit costs, including discount rate and updated pension asset valuation information. In addition, several staff adjustments and corrections to revenue requirement were not contested by any party.[11] The uncontested adjustments and corrections are also accepted for purposes of the revenue requirement determination.

Other Deferrals

As a result of the ratemaking process, and with reasonable regulatory assurance of future cost recovery, utilities sometimes include allowable costs in a period other than the period in which those costs would be charged to expense by an unregulated enterprise in accordance with generally accepted accounting principles. These differences usually relate to the timing of the recognition of a cost. The result of these timing differences is the creation of deferred accounts. The Commission's policy on deferred accounts is set forth in the Commission's Statement of Position, SOP 94-01. Appendix E is a list of those deferred accounts approved for WPSC, the amortization period, and the amount of Wisconsin jurisdictional 2016 test-year amortization expense. It is appropriate to treat all amortizations as normal test-year expenses by recording the full amounts in the test year.

Summary of Operating Income Statements at Present Rates

In addition to the findings regarding the specific items discussed in this Final Decision, all other uncontested Commission staff adjustments to WPSC's filed operating income statements are

[11] *See* Ex.-PSC-Kettle-1 (PSC REF#: 274618) and Rebuttal-WPSC-Moras-r (2) (PSC REF#: 276226).

appropriate. Accordingly, the estimated Wisconsin retail electric and natural gas utility operating income statements at present rates for the 2016 test year, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	Electric (000's)	**Natural Gas** (000's)
Operating Revenues		
Sales of Electricity	$1,014,049	
Sales of Natural Gas Including Transportation		$302,320
Other Operating Revenues Including Opportunity Sales	45,752	1,704
Other Income - Before Tax	(193)	
Total Operating Revenues	$1,059,608	$304,024
Operating Expenses		
Fuel and Purchased Power	$479,505	
Purchased Gas Expense		$171,855
Other Production Expense	73,619	4,621
Transmission Expense	305	713
Distribution Expense	48,424	24,509
Customer Accounts Expense	15,107	10,255
Customer Service Expense	22,660	4,211
Administrative and General Expense	61,508	17,369
Total Operation & Maintenance Expense	$701,128	$233,533
Depreciation Expense	89,615	16,747
Amortization Expense	13,918	
Taxes Other Than Income Taxes	40,531	5,889
Income Taxes	65,890	15,337
Total Operating Expense	$911,082	$271,506
Net Operating Income	$148,526	$32,518
Adjustments to Net Operating Income		(33)
Adjusted Net Operating Income	$148,526	$32,485

Average Net Investment Rate Base

All uncontested Commission staff adjustments to WPSC's filed average electric and natural gas net investment rate bases are appropriate. Accordingly, the estimated Wisconsin retail electric and natural gas utility average net investment rate bases for the 2016 test year, which are considered reasonable for the purpose of determining the revenue requirements in this proceeding, are as follows:

	Electric (000's)	Natural Gas (000's)
Utility Plant in Service	$3,442,383	$796,842
Less: Accumulated Depreciation	1,758,649	447,990
Net Plant	$1,683,734	$348,852
Add: Gas in Storage		20,271
Fuel Inventory	37,359	
Materials and Supplies	32,281	3,001
Other Investments - net of tax	530	
Less: Customer Advances	8,216	3,222
Average Net Investment Rate Base	$1,745,688	$368,902

Pro Forma Rate of Return

The adjusted net operating income at present rates for purposes of this proceeding for the test year ending December 31, 2016, results in a rate of return on average net investment rate base of 8.51 percent for Wisconsin retail electric utility operations and 8.81 percent for Wisconsin retail natural gas utility operations.

Financial Capital Structure and Dividend Restriction

The long-term range for WPSC's common equity ratio, on a financial basis, is 49 percent to 54 percent common equity. Historically, the capital structure for WPSC has been balanced with equity infusions from, and special dividends to, its parent company to maintain a test-year average equity near a target level within the approved range. An appropriate target level for the test-year average common equity measured on a financial basis is 51 percent, provided that the amount of the equity infusion will offset new indebtedness and does not result in cash or cash equivalent holdings. This target level is consistent with the 49 to 54 percent range established by the Commission.

In calculating capital structures, on a financial basis, this Commission has imputed debt associated with obligations not reported on balance sheets. The imputed debt results in additional costs to ratepayers because the utility is required to add sufficient common equity to maintain its target equity level, and the higher return earned on the additional equity increases the weighted cost of capital. In addition, imputing debt for off-balance sheet obligations is not a common practice of other state utility commissions. The Commission is not obligated to adopt the risk assessment of an outside rating agency and will independently examine off-balance sheet obligations, based on its assessment of risk.

To independently examine off-balance sheet debt obligations, it is reasonable to require that WPSC submit detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent. The information shall include, at minimum: (1) the minimum annual lease and PPA obligations; (2) the method of calculation along with the calculated amount of the debt equivalent; and (3) supporting documentation, including all reports, correspondence and any other justification that clearly established Standard & Poor's (S&P) and other major credit rating agencies' determination of the off-balance sheet debt equivalent, to the extent available, and publicly available documentation when S&P and other major credit rating agencies' documentation is not available.

For the test year, the Commission finds it reasonable to impute $21,131,385 of debt equivalent, and $1,051,000 of subsidiary debt related to WPSC's subsidiary, WPS Leasing. Of the $21,131,385 amount, $491,283 is relating to non-purchased power operating leases. The operating lease imputation is based on 100 percent of the present value of the payment streams, while the subsidiary debt is the forecasted average principal outstanding for the test year.

An additional $20,421,077 of imputed debt relates to PPAs and includes approximately $18,850,301 for debt equivalence for contracted capacity payments. The imputations are based on a 40 percent risk factor applied to the present value of the payment streams. An additional $1,198,934 of debt equivalence is associated with calculated proxy capacity payment associated with energy contract minimums and a 25 percent risk factor adjustment. Use of a 25 percent risk factor reflects the risk associated with the recovery of this expense through the fuel clause.

Consistent with its treatment in previous dockets, the Commission determined that no debt imputation should be included for wind, parallel generation, and renewable portfolio standard PPAs. The Commission determines that the debt imputation for the wind related land leases shall be based on the lesser of the present value of the payments, assuming continued operation of the wind turbines and the present value of the termination payments if the operation is discontinued. For the test year, one year of lease payments was treated as the proxy termination payment with a present value of $219,024.

Lastly, neither WPSC nor Commission staff included debt imputation associated with obligation categories of advances from associated companies, affiliated capital lease, purchased power capital leases, guarantees, underfunded pension and other post-retirement employee benefit plans, or asset retirement obligations. For each of the above categories, either WPSC does not have any obligations or this Commission has previously determined not to include debt imputations for these categories.

Incorporating the above debt equivalences for off-balance sheet debt obligations and other Commission determinations, WPSC's financial capital structure for the test year will consist of 51.00 percent common equity, 1.74 percent preferred stock, 44.07 percent long-term debt, 2.44 percent short-term debt, and 0.76 percent debt equivalence for off-balance sheet obligations, including subsidiary debt. The 51.00 percent common equity, on a financial basis, is consistent with the common equity target.

Assessing the reasonableness of WPSC's capital structure depends upon three important principles. First, capital structure decisions must be based on WPSC's needs, not on the needs of the non-utility operations of the holding company. Second, the capital structure should provide adequate flexibility for WPSC and the Commission to allow proper utility investment now and in the future. Third, the dividend policy of WPSC should be similar to typical electric utility dividend practices as long as WPSC is below the estimated test-year common equity ratio.

Generally, under Wis. Stat. § 196.795, the utility's capital needs must take precedence over non-utility needs if ratepayers are to be protected. The identification of utility needs goes beyond foreseeable needs. WPSC must have flexibility to finance both foreseen and unforeseen capital requirements.

In previous dockets, the Commission has recognized the need to protect ratepayers and to ensure that utility needs are placed before non-utility needs in capital structure and dividend policy choices. WPSC's previous dividend restriction limited WPSC's dividends to 103 percent of the prior year's common dividend, and required that any special dividend would not cause the common equity, on a financial basis, to drop below the projected calendar year average of 51.00 percent or the dollar amount of equity reflected in the test year, without prior Commission approval. Since WPSC's last rate case, Integrys has been acquired by WEC Energy Group. For consistency with the other operating companies within the WEC Energy Group holding company, the Commission determines that the wording of WPSC's dividend restriction shall be changed to match the wording of the dividend restrictions of the other operating utilities within its new holding company. The new dividend restriction states:

> WPSC shall not pay dividends in excess of the amount forecasted in this proceeding if such dividends cause the average annual common equity ratio, on a financial basis, to fall below the test-year authorized level of 51.00 percent. WPSC shall not pay a special dividend in excess of the forecasted dividends at the end of the year unless the additional payment does not reduce the average annual common equity ratio, on a financial basis, below the forecasted level of 51.00 percent.

Ten-Year Financial Forecast

WPSC's 10-year financial forecast is useful to the Commission and shall be submitted in future rate cases. The 10-year forecast can be combined with other business risk information to assess capital structure needs and rate of return requirements.

Regulatory Capital Structure and Cost of Capital

As in the previous rate case docket, in order to arrive at the common equity amount for WPSC's regulatory capital structure, Commission staff deducted from booked common equity WPSC's investment in common equity of ATC, net of deferred income taxes associated with transmission assets transferred to ATC along with other non-utility items. Consequently, a reasonable utility rate making capital structure for the purposes of establishing just and reasonable rates for the test year consists of 50.47 percent common equity, 1.78 percent preferred stock, 45.25 percent long-term debt, and 2.50 percent short-term debt.

Short-Term Debt

WPSC's test-year capital structure contains approximately $72 million of short-term debt in the form of commercial paper. A reasonable estimate of WPSC's average cost of short-term commercial paper debt for the test year is 1.20 percent. The forecast is based on the average of commercial paper rate estimates provided by the *Blue Chip Financial Forecasts* newsletter. This is a reasonable and objective method of determining WPSC's short-term debt costs.

Long-Term Debt

WPSC's test-year long-term debt includes a financing of $250 million of 30-year debt in November 2015. A reasonable estimate for the cost of the issuance is 4.20 percent. The resulting embedded cost of long-term debt is 4.65 percent for the test year.

Preferred Stock

The average cost of preferred stock is 6.08 percent for the test year.

Return on Common Equity

The principal factor used to determine the appropriate return on equity is the investors' required return. Authorized returns of less than the investors' required return would fail to compensate capital providers for the risks they face when providing funds to the utility. Such sub-par returns would make it difficult for a utility to raise capital on an ongoing basis. On the other hand, authorized returns that exceed the investors' required return would provide windfalls to utility investors as they would receive returns that are in excess of the necessary level. Such high returns would be unfair to utility consumers who ultimately pay for those returns.

In reaching its determination as to the appropriate return on equity, the Commission must balance the needs of investors with the needs of consumers, with due considerations to economic and financial conditions, along with public policy considerations. When making this decision, the Commission exercises its legislative function in setting policy based upon its balancing of these factors. The law recognizes the great degree of discretion exercised by the Commission in making such decisions and affords such decisions great weight deference. The use of this discretion is also necessary because the investors' required return cannot be measured with precision.

In this proceeding, WPSC's application requested to maintain its current authorized return of 10.20 percent. Commission staff suggested that the appropriate return on equity be set somewhere in the range from 9.80 percent to 10.20 percent and used 10.00 percent in the revenue requirement. CUB recommended a return of 8.75 percent. The revenue impact for each 10 basis points is approximately $1.5 million for electric and $300,000 for natural gas.

Commission staff provided testimony in this case regarding the effect of reduced revenue volatility on earnings risk.[12] In docket 6690-UR-123, the Commission approved customer charge increases, resulting in a greater percentage of WPSC's revenues being recovered from fixed charges, rather than volumetric sales. Volumetric sales are subject to volatility due to customer behavior and weather, while customer charges are dependent upon the number of customers. Commission staff estimated the reduced revenue could be reflected in a reduction of the required return on equity between 35 to 142 basis points, depending on the level of the fixed charges approved in this case and the debt rate used. CUB agreed that it would be appropriate to reduce the return on equity to reflect the utility's fixed revenues. WPSC argued that it is not appropriate to isolate one factor when estimating a utility's cost of capital. Financial markets price a utility's capital based on the overall regulatory treatment and financial health.

The Commission finds that the models used to estimate the return on equity in this case indicate that a reduction from the currently authorized return on 10.20 is reasonable. In addition, factors such as forward-looking test years, annual rate cases, and higher levels of fixed charges, mitigate some risk and indicate a lower required return. The Commission has traditionally made gradual adjustments to the return, rather than large and sudden changes. Given these

[12] *See, e.g.*, Direct-PSC-Pepin (PSC REF#: 276056); Ex.-PSC-Pepin-1 (PSC REF#: 274636); Surrebuttal-PSC-Pepin (PSC REF#: 275922).

considerations, the Commission finds that the balance is struck most reasonably in this proceeding by authorizing a return on equity capital of 10.00 percent.

Commissioner Huebsch dissents (and writes separately).

The authorized return on equity reflects all of the financial factors that affect the utility's cost of equity and as a result, it is not reasonable to identify a specific reduction attributable to any single factor, such as the level of customer charges.

Accordingly, the average utility capitalization ratios, annual cost rates, and the composite cost of capital rate considered reasonable and just for setting rates for the test year are as follows:

	Amount	**Percent**	**Annual Cost Rate**	**Weighted Cost**
Utility Common Equity	$1,449,953,220	50.47%	10.00%	5.05%
Preferred Stock	$51,188,200	1.78%	6.08%	0.11%
Long-Term Debt	$1,300,100,000	45.25%	4.65%	2.10%
Short-Term Debt	$71,916,075	2.50%	1.20%	0.03%
Total Utility Capital	$2,873,157,496	100.00%		7.29%

The weighted cost of capital of 7.29 percent is reasonable for WPSC for the test year. It generates an economic cost of capital of 10.75 percent and a pre-tax interest coverage ratio of 5.05 times on the regulatory capital structure, and 5.09 times on the test-year financial capital structure.

Rate of Return on Rate Base

The 7.29 percent composite cost of capital must be translated into a rate of return that can then be applied to the average net investment rate base and used to compute the overall return requirement in dollars. The estimate of WPSC's average net investment rate base plus CWIP for the test year is 94.41 percent of capital applicable primarily to utility operations plus deferred investment tax credits. This estimate reflects all appropriate Commission adjustments and is a reasonable and just factor for use in translating the composite cost of capital into a return requirement applicable to the average net investment rate base.

To allow a test-year current return on the average CWIP balance not accruing AFUDC at 100 percent, an adjustment must be added to the return on net investment rate base. Given WPSC's financing and cash flow requirements in the test year and the forecasted amount of construction activity, the Commission finds it reasonable to allow a current return on 50 percent of CWIP that is not accruing 100 percent AFUDC for the test year.

Consistent with prior Commission decisions, it is reasonable to include adjustments to the return on net investment rate base to allow a current return on the unamortized balances of the De Pere Energy Center premium; the Crane Creek revenue normalization; the Fox Energy Center purchased power contract buyout, acquisition adjustment, and CSA amortization; the Glenmore Wind Asset retirement; the early retirement of Pulliam Units 5 and 6 and Weston Unit 1; and the deferred tax proration when setting rates based on a forecasted test year, at the authorized adjusted weighted average cost of capital. In addition, it is reasonable to include adjustments to the return on net investment rate base to allow a current return on the unamortized balances of the Columbia and Edgewater precertification and preconstruction deferral balance, the EPA Notice of Violation deferral, and the 2014 fuel true-up balance at the authorized short-term debt rate.

Accordingly, the Commission finds that the rates of return on average Wisconsin retail electric and natural gas net investment rate bases, which are reasonable for the purpose of determining just and reasonable rates in this proceeding, are as follows:

	Electric	Natural Gas
Weighted Cost of Capital	7.29%	7.29%
Ratio of Average Net Investment Rate Base Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	94.41%	94.41%
Adjusted Cost of Capital to Derive Percent Return Requirement Applicable to Average Net Investment Rate Base	7.72%	7.72%
Adjustment to Return Requirement to Provide Current Return on CWIP, De Pere Energy Center, Crane Creek, Fox Energy Center, Glenmore, the early retirement of Pulliam 5 and 6 and Weston 1, and the deferred tax proration at the Adjusted Weighted Cost of Capital	0.51%	0.08%
Adjustment to Return Requirement to Provide Current Return on Columbia and Edgewater precertification and preconstruction balances, the EPA Notice of Violation, and the Wisconsin electric fuel true-up from 2014 at the composite short-term debt rate	0.01%	0.00%
Required Rate of Return on Average Net Investment Rate Base	8.24%	7.80%

Revenue Requirement

On the basis of the findings in this Final Decision, a $7,874,000 decrease in Wisconsin retail electric utility revenues and a $6,225,000 decrease in Wisconsin natural gas utility revenues are reasonable for the purpose of determining reasonable and just rates in this proceeding and are computed as follows:

	Electric	Natural Gas
Pro Forma Return on Average Net Investment Rate Base at Present Rates	8.51%	8.81%
Required Return on Average Net Investment Rate Base	8.24%	7.80%
Earnings Deficiency (Excess) as percent of Average Net Investment Rate Base	-0.27%	-1.01%
Average Net Investment Rate Base (000's)	$1,745,688	$368,902
Amount of Earnings Deficiency (Excess) on Average Net Investment Rate Base (000's)	$(4,713)	$(3,726)
Revenue Deficiency (Excess) to Provide for Earnings Deficiency Plus Federal and State Income Taxes (000's)	$(7,874)	$(6,225)

Electric COSS, Rates, and Reporting

Electric Cost of Service

WPSC, CUB, WIEG, and Commission staff testified regarding COSS issues and the appropriate allocation methods for allocating the plant and operating expenses that make up WPSC's revenue requirement. At the request of Commission staff, WPSC prepared six COSS models representing a range of COSS models the Commission has historically relied upon in prior WPSC rate cases. These models covered a variety of different allocations including 12CP (coincident peak) and 4CP production allocators, demand/energy splits for production plant, and a 100 percent demand allocation for distribution plant. WPSC prepared the COSS models using its filed revenue requirement and updated the models using Commission staff's audit-adjusted revenue requirement. WIEG introduced two additional COSS models, including a modified 4CP model and a 1CP model. CUB did not prepare its own COSS, but indicated that it agreed most closely with the Locational model. Consistent with past practice, Commission staff did not endorse a specific COSS model, but noted that the models presented a reasonable range of outcomes that the Commission could use to determine the actual allocations to each class of customers.

The Commission appreciates the efforts of WPSC and the other parties to present a range of reasonable cost allocation outcomes in this proceeding. The testimony on cost allocation in this case is extensive; each of the various COSS present different philosophies about how the costs of the system should be allocated. Nonetheless, the Commission is not persuaded by the evidence that any of the proposed methods are unreasonable. As a result, the Commission finds that it is reasonable to continue its long-standing practice of relying on multiple COSS models, as well as other factors such as customer bill impacts, when determining the final allocation of the revenue requirement.

Electric Revenue Allocation

WPSC proposed a revenue allocation using Commission staff's audit adjusted revenue requirement that closely followed its preferred COSS model, the 1/3 Phase model. Commission staff also prepared a revenue allocation that generally followed the allocation proposed by WPSC, but narrowed the range of variance so that all classes were closer to the system average, based on Commission staff's adjusted revenue requirement. CUB proposed a revenue allocation that narrowed the range of class increases even further. WIEG did not propose a specific revenue allocation in this case, but recommended that the increase for each class be capped at no more than 1.25 times the overall increase. WPC supported WIEG's proposal.

The overall revenue requirement in this case includes credits associated with excess SEERA contributions, as discussed above. Since these dollars were contributed by only certain customers, the Commission finds it reasonable to return the excess contributions to those customers in RSM rate classes. These include the residential, small commercial, and medium commercial customers. The 1-year credits are separately listed in Appendix B, and the rates shown in Appendix B are inclusive of the credits.

The Commission generally uses electric COSS models and other information as a guide for determining the final revenue allocation. Because the final revenue requirement results in a decrease to electric revenues, the revenue allocation proposals must be adjusted to provide an overall decrease. The Commission finds it reasonable to base the final revenue allocation on CUB's proposed allocation, which results in an overall decrease, with the Cp-1 class capped at zero percent to avoid disparate revenue changes among classes. The final electric revenue allocation, along with the electric rate design described below, is shown in Appendix B.

Electric Rate Design

Like its COSS models and revenue allocation, WPSC initially proposed a rate design based on its proposed overall increase of 9.71 percent, and subsequently revised its rate design based on Commission staff's proposed 1.75 percent increase. The WPSC rate designs under both revenue requirement levels included higher demand charges, higher customer charges for energy-only rate classes, and lower energy charges. Commission staff proposed maintaining customer charges at current levels, and a more even split of the increase between demand and energy rates.

CUB proposed maintaining customer charges for the energy-only rate classes at their current levels. WIEG and Wal-Mart did not develop specific rate designs, but agreed with WPSC's proposal to apply a larger share of the increase on demand charges. WPC supported WIEG's proposal.

Customer Charges

WPSC proposed a rate design that set the customer charges for residential customers at $25 per month, and at $28 per month and $43 per month for single-phase and three-phase small commercial customers, respectively, accompanied by a proportional decrease in the variable energy charge from $0.1161/kWh to $0.10644/kWh. The proposed customer charges represent increases of 32.6 percent, 12.0 percent, and 7.5 percent, respectively. The Commission recognizes that the appropriate level of customer charges is a heavily contentious issue both in Wisconsin and nationwide. Commission staff, CUB, RENEW Wisconsin (RENEW), The Alliance for Solar Choice (TASC), and Environmental Law and Policy Center (ELPC) argued that the customer charges should be maintained at their current levels. Fair Rates for Wisconsin's Dairyland supported WPSC's customer charge proposal.

In this proceeding, WPSC asked the Commission to continue its efforts to more closely align fixed customer charges with fixed costs and to continue the rate restructuring that the Commission undertook in WPSC's prior rate case proceedings. Determination of the appropriate structure and reasonable level of charges goes to the core reason why Wisconsin created this Commission: to bring to bear this agency's expertise and knowledge about rates, how they are designed, the kind of price signals to be sent to customers, and the type of behavior this Commission wants to incent as a matter of sound public policy. In designing rates, the Commission exercises a legislative function in setting policies that reflect the changing nature of the utility industry, which includes the emergence of increased customer interest in distributed generation and other measures to reduce electric usage. Each of the parties recognized this basic principle when they asked the Commission to consider various public policy objectives in setting the customer charges. Wisconsin courts have long held that the Commission has wide discretion in determining the factors upon which it may base its rate decisions. Further, the Commission is not bound to any single regulatory formula; it is permitted to make the pragmatic adjustments, which may be called for by particular circumstances, unless its statutory authority plainly precludes this. To the extent that setting rates requires the weighing of evidence, the Commission must use its special experience, technical competence and specialized knowledge to evaluate the evidence and identify a reasonable result, bearing in mind the various public policies that may be impacted by various rate making decisions. Wis. Stat. §§ 227.57 (6), (8) and (10).

In support of its proposal, WPSC provided substantial evidence about the fixed and variable costs associated with providing electric service to its various customer classes. A recitation of all the record evidence is unnecessary and not required. *State ex rel. Harris v. Annuity & Pension Bd.*, 87 Wis. 2d 646, 661, 275 N.W.2d 668 (1979). WPSC, like all utilities, are legally required to provide reliable and adequate electric service to all customers. Wis. Stat. § 196.03. To meet its obligation to provide service, WPSC must therefore invest in infrastructure to serve customers, regardless of whether any given customer actually uses any electricity. (Direct-WPSC-Ferguson-11.) There is no dispute that there are certain fixed costs incurred from simply connecting to the system and that the utility is obligated to make its system available regardless of the frequency to which that system will be relied upon by certain customers. The electric industry is capital intensive, and building and operating the necessary infrastructure comes at a cost. WPSC submitted evidence demonstrating that its fixed costs to serve a residential customer is $68.61. (Ex.-WPSC-Hoffman-Malueg-1; Direct-WPSC-Ferguson-9.) Recognizing the need to realign rates with cost in a gradual matter over time, WPSC requested an increase in the monthly customer charge of $25 for residential customers that is significantly less than its total fixed costs to serve residential customers because it represents a balance between the principles of gradualism and cost causation. (Direct-WPSC-Ferguson-9.)

One of the reasons cited by WPSC for collecting a greater portion of fixed costs through monthly customer charges is to mitigate the subsidy paid by high-use customers to lower-use customers. (*Id.*, at 12.) To the extent a customer is a low-use customer, the customer reduces the portion of the utility’s fixed costs he or she pays, and these costs must be recovered from other customers. As WPSC witness Ms. Ronda Ferguson observed:

> The current rate structures create subsidies between high and low energy use customers. Some of the customers do not use enough energy to cover the fixed costs associated with serving them. Customers who use more energy effectively make up the shortfall through variable energy charges that are designed to recover fixed costs as well as the cost of energy.

(Direct-WPSC-Ferguson-12.)

The Commission generally agrees with WPSC's arguments for increasing the customer charges and notes that its policy reasons, as outlined in the Final Decision in docket 6690-UR-123, WPSC's more recent rate case, supporting increases in fixed charge with a corresponding decrease in the variable energy charge, have not changed. The Commission agrees with WPSC that the continued analysis of an appropriate customer charge must begin with attempting to better align the customer charge with the fixed costs of providing service, regardless of the amount of energy used. As discussed further below, WPSC provides a compelling case that its customer charge continues to be insufficient to recover its fixed costs.

Starting with the principle that customer charges should generally align with fixed costs, the question becomes what those fixed costs actually are. As in previous rate cases, certain intervenors and WPSC do not agree on what costs should be considered as "fixed costs" for inclusion in the customer charge. CUB witness Jonathan Wallach argued that the customer charge should be set a level that reflects the incremental costs of adding another customer. To that end, he relied on the Locational COSS model, which does not assign any distribution plant as customer classified costs. WPSC relied on other COSS models that use a minimum system analysis to assign a portion of the distribution system as customer classified costs. This reflects WPSC's belief that the customer charge should reflect a utility's short-term fixed costs that do not vary with a customer's usage.

Notwithstanding these arguments, the Commission does not need to rely on either argument in making its determination of what is appropriately reflected in the customer charge in this case. All parties agree, to some extent, that there are fixed costs incurred by the utility regardless of the actual usage of any particular customer. The determination of what costs are properly categorized as "fixed costs" for purposes of setting an appropriate customer charge is intertwined with value and policy judgements inherent in setting rates designed to send accurate price signals. The record is replete with studies and data about the various fixed and variable costs to provide reliable electric service. This information guides the Commission's determination of a reasonable rate design. It is clear the Commission is not obliged to categorize with exacting certainty the particular costs to serve any one customer category or class of customers, as long as the overall rates are designed to achieve the needed revenue requirement for the utility and are reasonable.

> It is well established that the Commission, in designing a rate structure to recover the revenue to which it is entitled, as shown by a cost analysis, has wide discretion in determining the factors upon which it may base its precise rate schedule. It is not required to apply a cost-of-service formula to each class of customer or to each customer within a class.
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> It seems clear that no responsibility rests upon the Commission to make the exacting type of cost study that is urged by the appellants. It is sufficient that there be, as there is here, substantial evidence in the record to support the rate as a whole.

City of West Allis v. Pub. Serv. Comm'n of Wis., 42 Wis. 2d 569, 578-79, 161 N.W.2d 401 (1969).

Additionally, while the Commission is not required to determine the exact costs to serve each customer or class of the customers, the Commission nevertheless continues to rely upon its longstanding experience and approach to using COSS models. COSS attempt to classify every type of utility cost to provide information about what causes that cost and how it should be allocated. The Commission has traditionally declined to adopt a specific COSS as its preferred approach, and similarly declines here to select one party's proposed definition of "fixed cost" over another. As discussed more specifically below, substantial evidence in the record established that WPSC's fixed costs far exceeded the proposal to raise its customer charge under a variety of COSS models. Thus, it is sufficient in this case that WPSC's proposal moves the customer charge closer to its fixed costs. It is not pragmatic nor necessary at this time based upon the record in this proceeding to further define fixed costs. The Commission will continue to evaluate this question in the future on a case-by-case basis.

WPSC argued that its proposed customer charge for residential customers represents a reasonable approximation of the $28.28 per month customer-related cost of providing service to those customers that exist independent of the customer's consumption of electricity. (Direct-WPSC-Ferguson-8-9.) Of these costs, half ($14.83) consists of the service drop, metering, billing/customer information system, and other miscellaneous costs that are incurred regardless of whether the customer actually uses any electricity. (*Id.* at 9.) The other half of the costs ($13.84) consists of a portion of the secondary distribution lines, line transformers, and the primary feeder system of poles, conduit and conductors. (*Id*. at 10.) WPSC refers to these costs as "minimum system" costs because they represent, according to WPSC, the smallest poles, wire and related equipment that would be used to connect the customers to the distribution system, regardless of demand. (Direct-WPSC-Hoffman-Malueg-7.) All fixed costs in excess of the minimum system costs are allocated to the demand function and recovered through variable energy charges. WPSC noted that five of the six COSS presented in Ex.-WPSC-Malueg-3 support a residential customer charge of at least $25. The results of the 1P/3P, Standard, 4CP, Standard Capacity, and Time of Use COSS identify customer-related costs of between $25.52 to $26.33. (Rebuttal-WPSC-Hoffman-Malueg-11-12.).

ELPC and CUB claimed that WPSC's proposed customer charge increase is regressive in that it disproportionately harms low-income or low-use customers. ELPC witness Karl Rábago suggested that WPSC did not account for all low-income customers in its analysis of bill impacts because it only considered those customers on energy assistance with 12 monthly bills. (Direct-ELPC-Rábago-9.) WPSC updated its analysis to include the remaining low-income customers, and WPSC witness Ms. Ferguson introduced a study examining the relationship between energy consumption and income level. (Ex-WPSC-Ferguson-3.) This additional analysis showed that customers receiving energy-assistance, who are by definition low income customers, actually use over 150 kWh more electricity per month than the average residential customer. (Rebuttal-WPSC-Ferguson-8-11.) The Commission continues to be concerned with ensuring affordable, reliable electric service for Wisconsin's low-income consumers. However, the Commission does not find the evidence in this record to be compelling that increasing the customer charge would have a disproportionate impact on WPSC's low-income customers. As Ms. Ferguson noted in her testimony:

> The average residential customer would see no change in his/her total bill because the increase in the monthly fixed charge would be matched with a decrease in the variable energy rate.

(Direct-WPSC-Ferguson-12.)

TASC and RENEW argued that the Commission should decline to raise the customer charge because they claim other states are not taking similar action. These arguments are not persuasive especially in light of the record evidence in this specific proceeding which shows that WPSC is incurring more fixed costs than it is currently recovering in customer charges. The Commission's role is to evaluate policy matters for the state of Wisconsin using Wisconsin-specific policy goals and based on the evidence developed in each proceeding. Other states may have different approaches to achieving specific policy objectives and each utility incurs different costs in providing service to customers, which would necessarily lead to different outcomes. While the Commission may consider approaches taken by other states to determine a reasonable method of recovering the costs associated with providing service, the Commission is not bound by decisions made in other states and makes its decisions based on Wisconsin's policy objectives and the evidence in the record. For the reasons stated above, the decision to increase the customer charge meets those policy objectives, is based on substantial evidence and is reasonable.

Further, the Commission's determination that it is reasonable to increase customer charges to more closely align the charge with the utility's fixed costs to provide service is also consistent with its Final Decision in previous dockets, including docket 6690-UR-123. In that case, and in this proceeding, the Commission determined that the increase in customer charges reduces intra-class subsidies, provides more appropriate price signals, and encourages efficient utility-scale planning. The evidence in this record, supplied by Ms. Ferguson and others on behalf of WPSC, is persuasive that the actual level of fixed costs to serve each customer is greater than the current customer charges. The Commission, not the parties, is charged with evaluating the weight of the evidence. While CUB highlights the result of a single COSS

(Locational COSS) that identify costs less than $25.00, all of the other COSS, as noted above, support a customer charge of at least $25.00. It would be inconsistent with past Commission practice to rely solely upon the results of a single COSS.

Commission staff and others recommended that the customer charges be maintained at their current levels to allow customers more time to adjust to the increases that were approved by the Commission in previous rate cases. Commission staff and others also suggested that maintaining customer charges at current levels would provide Commission staff and the utility an opportunity to evaluate the effects of that change on customers before moving further towards aligning fixed costs with customer charges. Notwithstanding the policy considerations and evidence discussed above showing WPSC’s fixed costs exceed the customer charge, the Commission recognizes the short time period between WPSC’s rate cases and believes a gradual approach is reasonable.

In this docket, WPSC asked for a $25 per month residential customer charge. The Commission finds that it is reasonable to increase the customer charges more gradually than what was proposed by WPSC. The Commission finds it reasonable to increase the residential customer charge approximately 10.5 percent from existing fixed charges for customers in the energy-only classes; resulting in an increase from $19 to $21 per month for residential customers, from $25 to $27.63 per month for single-phase small commercial customers, and from $40 to $44.21 per month for three-phase small commercial customers. The Commission’s decision in this case strikes a balance between recovering the utility’s fixed costs through the customer charge and avoiding significantly changed rates for any individual customer.

The Commission believes its gradual approach to increasing the fixed charge will mitigate bill impacts to individual customers. However, the Commission is interested in reviewing further information about the effects of changes to WPSC's fixed charges over the past two rate cases to ensure that these changes are meeting the Commission's policy goals. As a result, the Commission directs WPSC to work with Commission staff to evaluate the impacts of increased fixed charges on customers, including evaluating the impacts on customer energy use and other behavior. The Commission delegates authority to the Administrator of the Division of Energy Regulation to design and implement the evaluation.

Medium Commercial (Cg-20) and Large Commercial and Industrial (Cp-1) Rates

Under WPSC's proposed rate design, the entire increase to the Medium Commercial (Cg-20) customer class would be placed on the demand charge. Such a rate design benefits high load factor customers. This rate design was supported by Wal-Mart. Commission staff proposed a rate design in which a proportionally larger share of the increase was reflected in the energy charge. At the final revenue allocation, the Medium Commercial class will see a 0.32 percent decrease. Although the overall allocation to the class is a decrease, the Commission agrees with WPSC and Wal-Mart that a higher demand charge better reflects the cost of service. Therefore, the Commission finds it reasonable to increase the demand charges by 5.0 percent above their current level to $13.905/kW in the summer and $9.272/kW in the winter and achieve the overall class decrease by reducing the energy charges appropriately. The on-peak energy charge is decreased from $0.06671 to $0.06448/kWh, and the off-peak energy charge is decreased from $0.04071 to $0.03935/kWh.

The initial rate design proposed by WPSC and endorsed by WIEG called for a larger proportion of the revenue allocation to the Large Commercial and Industrial class (Cp-1) to be recovered from demand charges. WPSC argued that this rate design would move the rates closer to the cost of service. Commission staff proposed an alternate rate design that had a slightly larger proportional increase on the energy charges. Because the Commission agrees with WIEG that the overall class increase for Large Commercial and Industrial customers should be set at zero percent, the Commission finds it reasonable to maintain the current rates for the class at this time.

Interruptible Credits

WIEG proposed to increase the credits for interruptible service. WIEG argued that the interruptible credits had not been increased for some time even though firm demand charges have increased, resulting in an increase in the differential between the firm demand charge and the interruptible demand charge. WPSC opposed increasing the interruptible credits, and proposed a rate design that maintained the credits at their present amounts. WPSC argued that interruptible customers need only make a short-term commitment to take interruptible service and that the current value of short-term capacity was very low. Commission staff's proposed rate design also maintained the interruptible credits at the current amounts.

The Commission finds that it is reasonable to maintain the interruptible credits at the current amounts. The existing credits provide an adequate incentive for industrial customers to designate load as interruptible and strikes a reasonable balance between low capacity prices in MISO and the cost of new entry.

Commissioner Montgomery dissents.

Real Time Market Pricing (RTMP) Tariff

Order point 9 of the Commission's Final Decision in docket 6690-UR-123 directed WPSC to work with WIEG and Commission staff to update the RTMP tariff. WPSC, WIEG, and Commission staff met several times over the last year to discuss this issue. Those meetings resulted in the parties reaching agreement upon a set of changes to the RTMP tariff adder, contract terms, and setting a maximum subscription limit. However, WPSC stated that its acceptance of the terms was conditional upon the Commission adjusting the test-year sales forecast for the Cp-1 class to reflect full customer subscription to the RTMP tariff. The Commission finds it reasonable to accept the agreed upon terms for the RTMP tariff, which include the following: an adder of $5.50/MWh, a 2-year minimum contract term, a 2-year notice for cancellation, and a program cap of 75 MW of nominated RTMP load. However, the Commission does not find it reasonable to adjust the Cp-1 sales forecast as requested. The Commission notes that such a change would be speculative because WPSC was not able to provide any specific estimates of the changes to Cp-1 billing units on which to base such an adjustment.

Customer Owned Generation Transmission Credits

Order Condition 10 of the Commission's Final Decision in docket 6690-UR-123 directed WPSC to work with RENEW and Commission staff on a proposed transmission credit for the PG-2A and PG-2B tariffs. In that case, the Commission did not find sufficient evidence to require a transmission credit for WPSC's customer owned generation tariffs. WPSC testified in this docket that distributed generation does not reduce its transmission expense because of the manner in which distributed generation resources are accounted for on the system. During discussions with Commission staff, WPSC revealed that for the purposes of reporting load to the transmission system operator, WPSC grosses up all customer owned generation greater than 20 kW. Commission staff noted that the other major utilities in the state gross up customer owned generation greater than 1 MW. The difference in methods results in no reduction in transmission expense for WPSC for distributed generation resources located in WPSC's service area because the load is reported to the transmission operator. In contrast, distributed resources located in other service territories reduce the utilities' transmission expense.

While consistency across the utilities in Wisconsin can be beneficial, it is not mandatory. Each utility has a unique service territory characteristics that in some cases may warrant different approaches. Currently, MISO does not have a standard for how this information is reported for transmission billing purposes, leaving the policy up to the various utilities. Further, there is insufficient evidence in the record to find that the method used by WPSC is unreasonable. For these reasons, the Commission does not find it necessary, at this time, to require WPSC to alter its report behind-the-meter generation calculations for reporting to MISO.

Commissioner Huebsch dissents.

The Commission also finds that it is unnecessary to establish a transmission credit for customers taking service under the PG-2A and PG-2B tariffs because there is insufficient evidence in the record as to whether, or to what extent, WPSC realizes any transmission savings from small distributed generation resources.

Natural Gas Cost-of-Service and Rates

WPSC, WIEG, and Commission staff testified regarding cost-of-service issues and the appropriate allocation methods for allocation the plant and operating expenses that make up WPSC's natural gas revenue requirement. WPSC prepared three COSS, including two requested by Commission staff. Additionally, WPSC and Commission staff prepared comprehensive revenue allocation and rate design proposals. While WIEG did not prepare a COSS or a comprehensive rate design, WIEG contributed to the cost-of-service, revenue allocation, and rate design discussion contained in the record.

Despite a lack of consensus regarding cost-of-service allocation methodologies, WPSC, WIEG, and Commission staff were able to arrive at an agreement on the natural gas revenue allocation and rate design proposed by Commission staff. The agreed upon revenue allocation produces class average rate decreases for all of WPSC's major natural gas service customer classes, and includes no change to the monthly fixed for residential, and small and medium commercial customers. Additionally, the volumetric local distribution service charges for the RG-3, CG-FST, CG-FS, and CG-FM customers include a credit reflecting a 1-year amortization of the SEERA over-collection refund. Should WPSC not file for a 2017 test-year rate case, these credits would sunset at the end of 2016.

The Commission commends the parties for working together with Commission staff to come to a settlement agreement regarding natural gas revenue allocation and rate design. Arriving at the agreed upon settlement required compromise on the part of all involved. This process is analogous to the one employed by the Commission itself when decisions must be rendered regarding utility revenue allocation and rate design as contested issues. The Commission has a long standing practice of considering more than one COSS, as well as other factors when allocating revenue responsibility and issuing rates. The revenue allocation and rate design settlement agreed to by the parties is consistent with this practice, and with the evidence presented in the record. Therefore, the Commission finds the agreement reached by the parties to be reasonable. The authorized natural gas rates and revenues are shown in Appendix C.

Order

1. This Final Decision takes effect one day after the date of service.

2. The authorized rate decreases and tariff provisions that expand the terms of service shall take effect January 1, 2016. WPSC shall file these rate decreases and tariff

provisions with the Commission and make them available to the public pursuant to Wis. Stat. § 196.19 and Wis. Admin. Code § PSC 113.0406(1)(a) and 134.13(1)(b) by that date.

3. By January 1, 2016, WPSC shall revise its existing rates and tariff provisions for electric and natural gas utility service, substituting the rate decreases and tariff provisions that expand the terms of service, as shown in Appendices B and C or as described in this Final Decision. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions

4. The authorized rate increases and tariff provisions that restrict the terms of service may take effect no sooner than January 1, 2016, provided that the utility files these rates and tariff provisions with the Commission and makes them available to the public pursuant to Wis. Stat. § 196.19 and Wis. Admin. Code § PSC 113.0406(1)(a) and 134.13(1)(b) by that date. If these rate increases and tariff provisions are not filed with the Commission and made available to the public by that date, they take effect one day after the date they are filed with the Commission and made available to the public.

5. WPSC may revise its existing rates and tariff provisions for electric and natural gas utility service, substituting the rate increases and tariff provisions that restrict the terms of service, as shown in Appendices B and C or as described in this Final Decision. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

6. WPSC shall prepare bill messages that properly identify the rates authorized in this Final Decision. WPSC shall provide the messages to customers no later than the first billing containing the rates authorized in this Final Decision, and shall file copies of these bill messages with the Commission before it provides the messages to customers.

7. WPSC shall file tariffs consistent with this Final Decision.

8. WPSC is authorized electric and natural gas rates, inclusive of the SEERA credits that sunset December 31, 2016, for the 1-year amortization of the extra contribution made to SEERA funds for the RSM customer classes.

9. WPSC shall work with Commission staff, on a study to evaluate the impacts of increased customer charges on customer behavior and energy use. The Commission delegates authority to the Administrator of the Division of Energy Regulation to design and implement this evaluation.

10. The authorized electric and natural gas rates include credits that sunset December 31, 2016, for the 1-year amortization of the over-recovery of SEERA revenue.

11. The electric fuel costs in Appendix D shall be used for monitoring WPSC's 2016 fuel costs pursuant to Wis. Admin. Code § PSC 116.06(3).

12. All 2016 fuel costs shall be monitored using a plus or minus 2 percent tolerance band.

13. The effect of the two PPAs entered into subsequent to Commission staff's audit of fuel costs shall be reflected in monitored fuel costs and authorized revenue requirement.

14. WPSC shall defer any minimum rail tonnage obligation costs incurred during 2016 for possible future rate recovery.

15. The escrow of network transmission charges and credits from ATC and MISO is extended through 2016. Any FERC-ordered ATC and MISO retroactive transmission asset rate of return refunds and any SSR costs and credit true-ups shall be escrowed for return to, or collection from, ratepayers in WPSC's next fuel or rate case proceeding.

16. WPSC is authorized to recover only the first 6 months of uneconomic dispatch costs associated with the seasoning of the ReACT™ activated coke pellets. Any uneconomic dispatch costs associated with the seasoning of the ReACT™ activated coke pellets after the first 6 months of seasoning shall be identified, removed from monitored fuel costs, and borne solely by the WPSC shareholders.

17. WPSC shall remove any ReACT™-related activated coke and ammonia costs incurred from forecasted fuel costs and include these items as capitalized ReACT™ costs.

18. Beginning January 1, 2016, WPSC shall file a report with the Commission for the preceding quarter, identifying any potential ReACT™ liquidated damages, both those that are pursued and those not pursued, the latter accompanied by an explanation as to why they were not pursued.

19. WPSC shall record annual conservation escrow accrual amounts for the 2016 test year of $16,346,123 for electric operations and $3,280,459 for natural gas operations. The level for electric utility operations consists of forecasted conservation expenditures of $16,046,221 plus the amortization of the overspent amount of $299,902. The level for natural gas operations consists of forecasted conservation expenditures of $4,411,207 less the amortization of the underspent amount of $1,130,748. WPSC shall continue to record these expense amounts annually until they are superseded by a Commission order authorizing new conservation escrow accruals.

20. WPSC shall record annual farm rewiring escrow accrual amounts for the 2016 test year of $710,171, which is comprised of $1,000,000 of estimated farm rewiring expenditures less the amortization of the underspent amount of $289,829. WPSC shall continue to record these expense amounts annually until they are superseded by a Commission order authorizing a new farm rewiring escrow accrual.

21. In future rate case filings, WPSC shall provide weather-normalized sales data for electric and natural gas operations at the rate schedule level.

22. WPSC shall defer the incremental revenue requirement associated with the disallowance of the $70 million ReACT™ cost overruns which includes the carrying cost of the plant not recovered at the weighted cost of capital and the related depreciation expense for 2016 only.

23. WPSC shall submit a 10-year financial forecast in its next rate case.

24. WPSC shall not pay dividends in excess of the amount forecasted in this proceeding if such dividends cause the average annual common equity ratio, on a financial basis, to fall below the test-year authorized level of 51.00 percent. WPSC shall not pay a special dividend in excess of the forecasted dividends at the end of the year unless the additional payment does not reduce the average annual common equity ratio, on a financial basis, below the forecasted level of 51.00 percent.

25. WPSC shall revise its dividend restriction wording to match the wording of WEPCO and WGC's dividend restriction as set forth in the Opinion section of this Final Decision.

26. WPSC shall submit, in its next rate case application, detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent. The information shall include, at a minimum: (1) the minimum annual lease and PPA obligations; (2) the method of calculation along with the calculated amount of the debt equivalent; and (3) supporting documentation, including all reports, correspondence and any other justification that clearly established S&P's and other major credit rating agencies' determination of the off-balance

sheet debt equivalent, to the extent available, and publicly available documentation when S&P and other major credit rating agencies' documentation is not available.

27. Jurisdiction is retained.

Concurrence and Dissent

Commissioner Huebsch concurs, in part, and dissents, in part and writes separately (see attached.

Dated at Madison, Wisconsin, this 17th day of December, 2015.

By the Commission:

Sandra J Paske

Sandra J. Paske
Secretary to the Commission

SJP:MJK:cmk:DL: 01278742

Attachments

See attached Notice of Rights

PUBLIC SERVICE COMMISSION OF WISCONSIN
610 North Whitney Way
P.O. Box 7854
Madison, Wisconsin 53707-7854

NOTICE OF RIGHTS FOR REHEARING OR JUDICIAL REVIEW, THE TIMES ALLOWED FOR EACH, AND THE IDENTIFICATION OF THE PARTY TO BE NAMED AS RESPONDENT

The following notice is served on you as part of the Commission's written decision. This general notice is for the purpose of ensuring compliance with Wis. Stat. § 227.48(2), and does not constitute a conclusion or admission that any particular party or person is necessarily aggrieved or that any particular decision or order is final or judicially reviewable.

PETITION FOR REHEARING

If this decision is an order following a contested case proceeding as defined in Wis. Stat. § 227.01(3), a person aggrieved by the decision has a right to petition the Commission for rehearing within 20 days of the date of service of this decision, as provided in Wis. Stat. § 227.49. The date of service is shown on the first page. If there is no date on the first page, the date of service is shown immediately above the signature line. The petition for rehearing must be filed with the Public Service Commission of Wisconsin and served on the parties. An appeal of this decision may also be taken directly to circuit court through the filing of a petition for judicial review. It is not necessary to first petition for rehearing.

PETITION FOR JUDICIAL REVIEW

A person aggrieved by this decision has a right to petition for judicial review as provided in Wis. Stat. § 227.53. In a contested case, the petition must be filed in circuit court and served upon the Public Service Commission of Wisconsin within 30 days of the date of service of this decision if there has been no petition for rehearing. If a timely petition for rehearing has been filed, the petition for judicial review must be filed within 30 days of the date of service of the order finally disposing of the petition for rehearing, or within 30 days after the final disposition of the petition for rehearing by operation of law pursuant to Wis. Stat. § 227.49(5), whichever is sooner. If an *untimely* petition for rehearing is filed, the 30-day period to petition for judicial review commences the date the Commission serves its original decision.[13] The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

If this decision is an order denying rehearing, a person aggrieved who wishes to appeal must seek judicial review rather than rehearing. A second petition for rehearing is not permitted.

Revised: March 27, 2013

[13] *See Currier v. Wisconsin Dep't of Revenue*, 2006 WI App 12, 288 Wis. 2d 693, 709 N.W.2d 520.

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates — 6690-UR-124

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WISCONSIN PUBLIC SERVICE CORPORATION
6690-UR-124

Rate Class		Present	Authorized	Revenue	Percentage
Description	**Name**	**Revenue**	**Revenue**	**Change**	**Change**
Residential Urban					
Residential Urban	Rg-1	$356,641,851	$355,729,549	-$912,301	-0.26%
Urban Residential Optional TOU	Rg3-OTOU	$14,139,981	$14,068,403	-$71,578	-0.51%
Urban Residential Optional 3TOU	Rg5-OTOU	$3,530,215	$3,513,377	-$16,838	-0.48%
		$374,312,046	**$373,311,329**	**-$1,000,717**	**-0.27%**
Small Commercial					
Small C&I - Urban (<50 KW)	Cg-1	$110,191,371	$106,141,240	-$4,050,131	-3.68%
Urban Small C&I Optional TOU	Cg3-OTOU	$9,842,396	$9,521,187	-$321,209	-3.26%
		$120,033,767	**$115,662,427**	**-$4,371,340**	**-3.64%**
12,500 - 25,000 kWh					
Small C&I - Rural (50 < KW> 100)	Cg-5	$35,393,006	$34,322,810	-$1,070,197	-3.02%
Medium C&I					
Cg TOU 100-1000 kW	Cg-20	$230,041,128	$229,321,173	-$719,955	-0.31%
Large C&I					
Cp Industrial > 1000 KW	Cp	$240,336,675	$240,113,962	-$222,713	-0.09%
Misc Rate Schedules					
Automatic Transfer Switch	ATS-1	$54,891	$55,632	$741	1.35%
Parallel Generation	Pg	$11,814	$11,814	$0	0.00%
Naturewise	NAT	$214,013	$214,013	$0	0.00%
		$280,718	**$281,459**	**$741**	**0.26%**
Lighting					
Lighting Service	Ls-1	$13,314,649	$12,852,174	-$462,474	-3.47%
Total		**$1,013,711,989**	**$1,005,865,334**	**-$7,846,655**	**-0.77%**

WISCONSIN PUBLIC SERVICE CORPORATION
6690-UR-124

Rate Schedule & Description of Rate Components	Present Rates	Authorized Rates
Rg-1 RESIDENTIAL - Urban		
Monthly Fixed Charge	$19.00	$21.00
Daily Fixed Charge	$0.6247	$0.6904
Monthly Fixed Charge (Seasonal)	$38.00	$42.00
Daily Fixed Charge (Seasonal)	$1.2493	$1.3808
Energy Charge (per kWh)	$0.10322	$0.09950
Rg-3 OTOU RESIDENTIAL		
Monthly Fixed Charge	$19.00	$21.00
Daily Fixed Charge	$0.6247	$0.6904
Monthly Fixed Charge (Seasonal)	$38.00	$42.00
Daily Fixed Charge (Seasonal)	$1.2493	$1.3808
Energy Charge (per kWh)		
On Peak	$0.19145	$0.18450
Off Peak	$0.06167	$0.06050
Water Heater		
Monthly Control Charge	$4.80	$4.80
Daily Control Charge	$0.1578	$0.1578
Monthly Control Charge (Seasonal)	$9.60	$9.60
Daily Control Charge (Seasonal)	$0.3156	$0.3156

WISCONSIN PUBLIC SERVICE CORPORATION
6690-UR-124

Rate Schedule & Description of Rate Components		Present Rates	Authorized Rates
Rg-5 OTOU RESIDENTIAL			
Monthly Fixed Charge		$19.00	$21.00
Daily Fixed Charge		$0.6247	$0.6904
Monthly Fixed Charge (Seasonal)		$38.00	$42.00
Daily Fixed Charge (Seasonal)		$1.2493	$1.3808
Energy Charge			
On Peak		$0.23376	$0.22250
Shoulder		$0.10322	$0.09950
Off Peak		$0.06167	$0.06050
Water Heater			
Monthly Control Charge		$4.80	$4.80
Daily Control Charge		$0.1578	$0.1578
Monthly Control Charge (Seasonal)		$9.60	$9.60
Daily Control Charge (Seasonal)		$0.3156	$0.3156
Cg-1 SMALL C&I (<50 KW)			
Monthly Fixed Charge	Single Phase	$25.00	$27.63
Daily Fixed Charge	Single Phase	$0.8219	$0.9084
Monthly Fixed Charge	Three Phase	$40.00	$44.21
Daily Fixed Charge	Three Phase	$1.3151	$1.4535
Monthly Fixed Charge (Seasonal)	Single Phase	$50.00	$55.26
Daily Fixed Charge (Seasonal)	Single Phase	$1.6438	$1.8168
Monthly Fixed Charge (Seasonal)	Three Phase	$80.00	$88.42
Daily Fixed Charge (Seasonal)	Three Phase	$2.6301	$2.9070
Energy Charge		$0.10785	$0.10130

WISCONSIN PUBLIC SERVICE CORPORATION
6690-UR-124

Rate Schedule & Description of Rate Components		Present Rates	Authorized Rates

Cg-3 SMALL C&L OPTIONAL TOU

Monthly Fixed Charge	Single Phase	$25.00	$27.63
Daily Fixed Charge	Single Phase	$0.8219	$0.9084
Monthly Fixed Charge	Three Phase	$40.00	$44.21
Daily Fixed Charge	Three Phase	$1.3151	$1.4535
Monthly Fixed Charge (Seasonal)	Single Phase	$50.00	$55.26
Daily Fixed Charge (Seasonal)	Single Phase	$1.6438	$1.8168
Monthly Fixed Charge (Seasonal)	Three Phase	$80.00	$88.42
Daily Fixed Charge (Seasonal)	Three Phase	$2.6301	$2.9070
Energy Charge (per kWh)			
On Peak		$0.19088	$0.18056
Off Peak		$0.06031	$0.05705
Water Heater			
Monthly Control Charge		$4.80	$4.80
Daily Control Charge		$0.1578	$0.1578
Monthly Control Charge (Seasonal)		$9.60	$9.60
Daily Control Charge (Seasonal)		$0.3156	$0.3156

Cg-5 SMALL C&I (50 < KW > 100)

Monthly Fixed Charge	Single Phase	$63.00	$63.00
Daily Fixed Charge	Single Phase	$2.0712	$2.0712
Monthly Fixed Charge	Three Phase	$100.80	$100.80
Daily Fixed Charge	Three Phase	$3.3140	$3.3140
Monthly Fixed Charge (Seasonal)	Single Phase	$126.00	$126.00
Daily Fixed Charge (Seasonal)	Single Phase	$4.1425	$4.1425
Monthly Fixed Charge (Seasonal)	Three Phase	$201.60	$201.60
Daily Fixed Charge (Seasonal)	Three Phase	$6.6279	$6.6279
Energy Charge		$0.09778	$0.09462

WISCONSIN PUBLIC SERVICE CORPORATION
6690-UR-124

Rate Schedule & Description of Rate Components		Present Rates	Authorized Rates
Cg20-TOU C&I (100-1000 KW)			
Monthly Fixed Charge	Secondary	$93.00	$93.00
Daily Fixed Charge	Secondary	$3.0575	$3.0575
Monthly Fixed Charge	Primary	$170.00	$170.00
Daily Fixed Charge	Primary	$5.5890	$5.5890
Customer Demand Charge (per kW)		$1.689	$1.689
Standby Demand Charge (per kW)		$2.251	$2.251
System Demand Charge (per kW)	Summer	$13.243	$13.905
	Winter	$8.830	$9.272
Energy Charge (per kWh)			
On-Peak		$0.06671	$0.06448
Off-Peak		$0.04071	$0.03935
Energy Limiter (per kWh)		$0.17394	$0.17340

WISCONSIN PUBLIC SERVICE CORPORATION
6690-UR-124

Rate Schedule & Description of Rate Components		Present Rates	Authorized Rates
Cp Large C&I (>1000 KW)			
Monthly Fixed Charge	Secondary	$665.00	$665.00
	Primary	$776.00	$776.00
	Transmission	$1,773.00	$1,773.00
Daily Fixed Charge	Secondary	$21.8630	$21.8630
	Primary	$25.5123	$25.5123
	Transmission	$58.2904	$58.2904
Distribution Demand Charge (per kW)	Secondary	$2.100	$2.100
	Primary	$1.850	$1.850
Substation - Transformer Capacity (per kW)		$0.588	$0.588
Standby Demand Charge (per kW)		$3.500	$3.500
System Demand Charges			
Peak - Summer	Secondary	$15.875	$15.875
Peak - Summer	Primary	$15.522	$15.522
Peak - Summer	Transmission	$15.309	$15.309
Peak - Winter	Secondary	$8.144	$8.144
Peak - Winter	Primary	$7.963	$7.963
Peak - Winter	Transmission	$7.854	$7.854
Intermediate - Summer	Secondary	$11.906	$11.906
Intermediate - Summer	Primary	$11.642	$11.642
Intermediate - Summer	Transmission	$11.482	$11.482
Intermediate - Winter	Secondary	$6.108	$6.108
Intermediate - Winter	Primary	$5.972	$5.972
Intermediate - Winter	Transmission	$5.891	$5.891
Interruptible Credit	Summer	-$6.301	-$6.301
	Winter	-$3.151	-$3.151

WISCONSIN PUBLIC SERVICE CORPORATION
6690-UR-124

Rate Schedule & Description of Rate Components		Present Rates	Authorized Rates

Cp-1 Large C&I (continued)

Energy Charge			
On-Peak	Secondary	$0.05945	$0.05941
On-Peak	Primary	$0.05771	$0.05767
On-Peak	Transmission	$0.05699	$0.05695
Off-Peak	Secondary	$0.03308	$0.03300
Off-Peak	Primary	$0.03211	$0.03203
Off-Peak	Transmission	$0.03170	$0.03163

Ls-1 Lighting Service

Company Owned		
Sodium Vapor		
5,670 Lumens (70W)	17.00	16.36
9,000 Lumens (100W)	17.52	16.86
14,000 Lumens (150W)	20.00	19.25
27,000 Lumens (250W)	24.65	23.72
45,000 Lumens (400W)	33.06	31.82
9,000 Lumens (100W) - Area	14.65	14.65
14,000 Lumens (150W) - Area	17.96	17.28
27,000 Lumens (250W) - Directional	29.90	28.78
45,000 Lumens (400W) - Directional	36.56	35.19
Metal Halide		
8,500 Lumens (150W)	23.55	22.66
26,000 Lumens (350W)	29.88	28.76
36,000 Lumens (400W) - (Closed)	33.06	31.82
26,000 Lumens (350W) - Directional	31.91	30.71
36,000 Lumens (400W) - Directional (Closed)	36.30	34.94
110,000 Lumens (1000W) - Directional	55.00	52.93

WISCONSIN PUBLIC SERVICE CORPORATION
6690-UR-124

Rate Schedule & Description of Rate Components	Present Rates	Authorized Rates
Ls-1 Lighting Service (continued)		
LED		
9,000 Lumens (100W) SV equivalent	14.47	14.47
14,000 Lumens (150W) SV equivalent	18.23	18.23
27,000 Lumens (250W) SV equivalent	23.83	22.93
Customer Owned (closed to new customers)		
Sodium Vapor		
9,000 Lumens (100W)	11.96	11.51
14,000 Lumens (150W)	14.08	13.55
27,000 Lumens (250 W)	18.00	17.32
45,000 Lumens (400W)	22.04	21.21
Metal Halide		
8,500 Lumens (150W)	16.82	16.19
26,000 Lumens (350W)	21.04	20.25
Common		
Wood Poles	5.08	4.89
Fiberglass Poles 25' / 20'	8.47	8.15
Fiberglass Poles 30' / 25'	10.94	10.53
Fiberglass Poles 35' / 30'	13.70	13.18
Fiberglass Poles 40' / 35'	22.79	21.93
Spans	2.24	2.16
Excess Footage - Mast Arm	0.23	0.22

WISCONSIN PUBLIC SERVICE CORPORATION
6690-UR-124

Rate Schedule & Description of Rate Components	Present Rates	Authorized Rates
Nature Wise		
NAT-R	$2.40	$2.40
NAT-C	$2.40	$2.40
ATS - Automatic Transfer Switch		
Fixed Charge		
Total Charge	$671.00	$680.00
Maintenance Only	$232.84	$236.00
Parallel Generation		
Pg-Solar Fixed Charge	$2.00	$2.00
Pg-BioGas Fixed Charge (Secondary)	$30.50	$30.50
Pg-BioGas Fixed Charge (Primary)	$58.30	$58.30
Fixed Charge	$20.00	$20.00
SEERA Credit - 2016 Rate Adjustment[1]		
Rg-1, Rg-3, Rg-5		-$0.00020
Cg-1, Cg-3		-$0.00018
Cg-5		-$0.00015
Cg-20		-$0.00010

Note[1] - SEERA Credit adjustments are included in the rates above and sunset on December 31, 2016.

WISCONSIN PUBLIC SERVICE CORPORATION
COMPARISON OF REVENUE FROM CURRENT AND AUTHORIZED RATES (INCLUDING GAS COSTS)
(All totals include Large Energy Customer's Act 141 charges and credits)

WPSC Customer Class	Current Revenue $	Authorized Revenue $	Change From Current $	Change From Current %
Residential				
Rg-3	$170,449,901	$166,521,894	($3,928,006)	-2.3%
Rg-T	$0	$0	$0	0.0%
Subtotal	$170,449,901	$166,521,894	($3,928,006)	-2.3%
Commercial & Industrial (0 - 2,000)				
Cg-FST	$12,948,444	$12,636,918	($311,526)	-2.4%
Commercial & Industrial (2,001 - 20,000)				
Cg-FS	$44,375,841	$43,529,694	($846,146)	-1.9%
Cg-TS	$38,166	$35,127	($3,039)	-8.0%
Cg-TSA	$130,700	$123,768	($6,932)	-5.3%
Subtotal	$44,544,706	$43,688,589	($856,117)	-1.9%
Commercial & Industrial (20,001 - 200,000)				
Cg-FM	$27,359,482	$26,912,895	($446,587)	-1.6%
Cg-IM	$1,522,975	$1,494,891	($28,084)	-1.8%
Cg-TM	$2,703,816	$2,654,856	($48,961)	-1.8%
Cg-TMA	$1,183,955	$1,163,910	($20,045)	-1.7%
Cg-SOS-M	$770,332	$761,354	($8,979)	-1.2%
Subtotal	$33,540,561	$32,987,905	($552,656)	-1.6%
Commercial & Industrial (200,001 - 2,400,000)				
Cg-FL	$9,328,473	$9,192,671	($135,801)	-1.5%
Cg-IL	$366,173	$362,592	($3,581)	-1.0%
Cg-TL	$7,573,596	$7,499,308	($74,288)	-1.0%
Cg-TLA	$92,647	$92,429	($219)	-0.2%
Cg-SOS-L	$0	$0	$0	0.0%
Subtotal	$17,360,889	$17,147,000	($213,889)	-1.2%
Commercial & Industrial (>2,400,000)				
Cg-ISL	$0	$0	$0	0.0%
Cg-TSL & CSR	$7,127,725	$7,052,778	($74,948)	-1.1%
Cg-TSLA	$0	$0	$0	0.0%
Subtotal	$7,127,725	$7,052,778	($74,948)	-1.1%
Interruptible Electric Generation				
Cg-IEGM	$0	$0	$0	0.0%
Cg-IEGL	$15,832,189	$15,544,124	($288,065)	-1.8%
Subtotal	$15,832,189	$15,544,124	($288,065)	-1.8%
Peak Day Backup	$0	$0	$0	0.0%
Daily Balancing	$516,000	$516,000	$0	0.0%
COMPANY TOTAL	$302,320,416	$296,095,209	($6,225,207)	-2.1%

Note: Base gas costs are included in both the Current Revenues and the Authorized Revenues above.

WISCONSIN PUBLIC SERVICE CORPORATION
COMPARISON OF REVENUE FROM CURRENT AND AUTHORIZED RATES (NOT INCLUDING GAS COSTS)
(All totals include Large Energy Customer's Act 141 charges and credits)

WPSC Customer Class	Current Revenue $	Authorized Revenue $	Change From Current $	Change From Current %
Residential				
Rg-3	$79,407,764	$75,479,758	($3,928,006)	-4.9%
Rg-T	$0	$0	$0	0.0%
Subtotal	$79,407,764	$75,479,758	($3,928,006)	-4.9%
Commercial & Industrial (0 - 2,000)				
Cg-FST	$5,515,940	$5,204,414	($311,526)	-5.6%
Commercial & Industrial (2,001 - 20,000)				
Cg-FS	$13,735,253	$12,889,107	($846,146)	-5.4%
Cg-TS	$38,166	$35,127	($3,039)	-8.0%
Cg-TSA	$130,700	$123,768	($6,932)	-5.3%
Subtotal	$13,904,119	$13,048,002	($856,117)	-6.2%
Commercial & Industrial (20,001 - 200,000)				
Cg-FM	$7,124,454	$6,677,867	($446,587)	-6.3%
Cg-IM	$400,689	$372,604	($28,084)	-7.0%
Cg-TM	$2,703,816	$2,654,856	($48,961)	-1.8%
Cg-TMA	$1,183,955	$1,163,910	($20,045)	-1.7%
Cg-SOS-M	$285,176	$276,197	($8,979)	-3.1%
Subtotal	$11,698,090	$11,145,434	($552,656)	-4.7%
Commercial & Industrial (200,001 - 2,400,000)				
Cg-FL	$1,445,750	$1,309,948	($135,801)	-9.4%
Cg-IL	$95,393	$91,811	($3,581)	-3.8%
Cg-TL	$7,573,596	$7,499,308	($74,288)	-1.0%
Cg-TLA	$92,647	$92,429	($219)	-0.2%
Cg-SOS-L	$0	$0	$0	
Subtotal	$9,207,386	$8,993,497	($213,889)	-2.3%
Commercial & Industrial (>2,400,000)				
Cg-ISL	$0	$0	$0	
Cg-TSL & CSR	$7,127,725	$7,052,778	($74,948)	-1.1%
Cg-TSLA	$0	$0	$0	
Subtotal	$7,127,725	$7,052,778	($74,948)	-1.1%
Interruptible Electric Generation				
Cg-IEGM	$0	$0	$0	
Cg-IEGL	$3,605,196	$3,317,131	($288,065)	-8.0%
Subtotal	$3,605,196	$3,317,131	($288,065)	-8.0%
COMPANY TOTAL	$130,466,221	$124,241,015	($6,225,207)	-4.77%

Note: No gas costs are included in either the Current Revenues or the Authorized Revenues above.

Wisconsin Public Service Corporation
Summary of Present and Authorized Natural Gas Rates
For the Test Year 2016

TYPE OF SERVICE	CUSTOMER CLASS	Monthly Equivalent	PRESENT RATES	AUTHORIZED RATES		Monthly Equivalent
Residential Firm Service						
Fixed Local Distribution Service	Rg-3 (Year Round)	$ 17.00	$ 0.5589	$ 0.5589	per Day	$ 17.00
	Rg-3 (Seasonal)	$ 34.00	$ 1.1178	$ 1.1178	per Day	$ 34.00
Volumetric Charges:						
Volumetric Local Distribution Service			$ 0.0610	$ 0.0546	per Therm	
Daily Balancing Service			$ 0.0005	$ 0.0005	per Therm	
Gas Supply Acquisition Service			$ 0.0196	$ 0.0098	per Therm	
Commercial & Industrial Firm Service - Annual Usage 0 - 2,000 therms						
Fixed Local Distribution Service	Cg-FST (Year Round)	$ 17.00	$ 0.5589	$ 0.5589	per Day	$ 17.00
	Cg-FST (Seasonal)	$ 34.00	$ 1.1178	$ 1.1178	per Day	$ 34.00
Volumetric Charges:						
Volumetric Local Distribution Service			$ 0.0610	$ 0.0546	per Therm	
Daily Balancing Service			$ 0.0005	$ 0.0005	per Therm	
Gas Supply Acquisition Service			$ 0.0196	$ 0.0098	per Therm	
Commercial & Industrial Firm Service - Annual Usage 2,001 - 20,000 therms						
Fixed Local Distribution Service	Cg-FS (Year Round)	$ 30.00	$ 0.9863	$ 0.9863	per Day	$ 30.00
	Cg-FS (Seasonal)	$ 60.00	$ 1.9726	$ 1.9726	per Day	$ 60.00
Volumetric Charges:						
Volumetric Local Distribution Service			$ 0.0927	$ 0.0904	per Therm	
Daily Balancing Service			$ 0.0005	$ 0.0005	per Therm	
Gas Supply Acquisition Service			$ 0.0162	$ 0.0081	per Therm	
Commercial & Industrial Firm Service - Annual Usage 20,001 - 200,000 therms						
Fixed Local Distribution Service	Cg-FM (Year Round)	$ 150.00	$ 4.9315	$ 4.9315	per Day	$ 150.00
	Cg-FM (Seasonal)	$ 300.00	$ 9.8630	$ 9.8630	per Day	$ 300.00
Volumetric Charges:						
Volumetric Local Distribution Service			$ 0.0708	$ 0.0702	per Therm	
Daily Balancing Service			$ 0.0005	$ 0.0005	per Therm	
Gas Supply Acquisition Service			$ 0.0149	$ 0.0075	per Therm	
Commercial & Industrial Firm Service - Annual Usage 200,001 - 2,400,000 therms						
Fixed Local Distribution Service	Cg-FL (Year Round)	$ 620.00	$ 20.3836	$ 21.3698	per Day	$ 650.00
	Cg-FL (Seasonal)	$ 1,240.00	$ 40.7672	$ 42.7397	per Day	$ 1,300.00
Enhanced Telemetering Service	Cg-FL (Year Round)	$ 12.00	$ 0.3945	$ 0.1973	per Day	$ 6.00
	Cg-FL (Seasonal)	$ 24.00	$ 0.7890	$ 0.3945	per Day	$ 12.00
Metered Demand Service			$ 0.1475	$ 0.1475	per Therm of Demand	
Volumetric Charges:						
Volumetric Local Distribution Service			$ 0.0342	$ 0.0331	per Therm	
Daily Balancing Service			$ 0.0005	$ 0.0005	per Therm	
Gas Supply Acquisition Service			$ 0.0115	$ 0.0058	per Therm	

Wisconsin Public Service Corporation
Summary of Present and Authorized Natural Gas Rates
For the Test Year 2016

TYPE OF SERVICE	CUSTOMER CLASS	Monthly Equivalent	PRESENT RATES	AUTHORIZED RATES		Monthly Equivalent
Commercial & Industrial Interruptible Service - Cg-IM & Cg-IEGM, Annual Usage 20,001 - 200,000 therms						
Fixed Local Distribution Service		$ 150.00	$ 4.9315	$ 4.9315	per Day	$ 150.00
Enhanced Telemetering Service		$ 12.00	$ 0.3945	$ 0.1973	per Day	$ 6.00
Volumetric Charges:						
Volumetric Local Distribution Service			$ 0.0708	$ 0.0708	per Therm	
Daily Balancing Service			$ 0.0005	$ 0.0005	per Therm	
Gas Supply Acquisition Service			$ 0.0126	$ 0.0063	per Therm	
Commercial & Industrial Interruptible Service - Cg-IL, Annual Usage 200,001 - 2,400,000 therms						
Fixed Local Distribution Service		$ 620.00	$ 20.3836	$ 21.3698	per Day	$ 650.00
Enhanced Telemetering Service		$ 12.00	$ 0.3945	$ 0.1973	per Day	$ 6.00
Metered Demand Service			$ 0.1475	$ 0.1475	per Therm of Demand	
Volumetric Charges:						
Volumetric Local Distribution Service			$ 0.0342	$ 0.0331	per Therm	
Daily Balancing Service			$ 0.0005	$ 0.0005	per Therm	
Gas Supply Acquisition Service			$ 0.0105	$ 0.0053	per Therm	
Commercial & Industrial Interruptible Service - Cg-ISL, Annual Usage >2,400,000 therms						
Fixed Local Distribution Service		$ 3,882.00	$ 127.6274	$ 121.8411	per Day	$ 3,706.00
Enhanced Telemetering Service		$ 12.00	$ 0.3945	$ 0.1973	per Day	$ 6.00
Metered Demand Service			$ 0.1000	$ 0.1000	per Therm of Demand	
Volumetric Charges:						
Volumetric Local Distribution Service			$ 0.0215	$ 0.0209	per Therm	
Daily Balancing Service			$ 0.0005	$ 0.0005	per Therm	
Gas Supply Acquisition Service			$ 0.0066	$ 0.0051	per Therm	
Commercial & Industrial Interruptible Service - Cg-IEGL, Annual Usage >200,000 therms						
Fixed Local Distribution Service		$ 6,995.00	$ 229.9726	$ 229.9726	per Day	$ 6,995.00
Enhanced Telemetering Service		$ 12.00	$ 0.3945	$ 0.1973	per Day	$ 6.00
Metered Demand Service			$ 0.0662	$ 0.0662	per Therm of Demand	
Volumetric Charges:						
Volumetric Local Distribution Service			$ 0.0131	$ 0.0103	per Therm	
Daily Balancing Service			$ 0.0005	$ 0.0005	per Therm	
Gas Supply Acquisition Service			$ 0.0080	$ 0.0051	per Therm	
Commercial & Industrial Interruptible Service - Seasonal Opportunity Sales - Cg-SOS-M Annual Usage > 200,000 therms						
Fixed Local Distribution Service		$ 150.00	$ 4.9315	$ 4.9315	per Day	$ 150.00
Volumetric Charges:						
Volumetric Local Distribution Service			$ 0.0708	$ 0.0708	per Therm	
Daily Balancing Service			$ 0.0005	$ 0.0005	per Therm	
Gas Supply Acquisition Service			$ 0.0126	$ 0.0063	per Therm	
Commercial & Industrial Interruptible Service - Seasonal Opportunity Sales - Cg-SOS-L, Annual Usage >200,000 therms						
Fixed Local Distribution Service		$ 620.00	$ 20.3836	$ 21.3698	per Day	$ 650.00
Enhanced Telemetering Service		$ 12.00	$ 0.3945	$ 0.1973	per Day	$ 6.00
Metered Demand Service			$ 0.1475	$ 0.1475	per Therm of Demand	
Volumetric Charges:						
Volumetric Local Distribution Service			$ 0.0342	$ 0.0331	per Therm	
Daily Balancing Service			$ 0.0005	$ 0.0005	per Therm	
Gas Supply Acquisition Service			$ 0.0105	$ 0.0053	per Therm	

Wisconsin Public Service Corporation
Summary of Present and Authorized Natural Gas Rates
For the Test Year 2016

TYPE OF SERVICE	CUSTOMER CLASS	Monthly Equivalent	PRESENT RATES	AUTHORIZED RATES		Monthly Equivalent
Residential Transportation Service - Rg-T						
Fixed Local Distribution Service		$ 17.00	$ 0.5589	$ 0.5589	per Day	$ 17.00
Enhanced Telemetering Service		$ 12.00	$ 0.3945	$ 0.1973	per Day	$ 6.00
Enhanced Administration Service		$ 37.50	$ 1.2329	$ 0.9205	per Day	$ 28.00
Volumetric Charges:						
Volumetric Local Distribution Service			$ 0.0610	$ 0.0554	per Therm	
Daily Balancing Service			$ 0.0005	$ 0.0005	per Therm	
Commercial & Industrial Transportation Service - Annual Usage <20,000 therms*						
Fixed Local Distribution Service		$ 30.00	$ 0.9863	$ 0.9863	per Day	$ 30.00
Enhanced Telemetering Service	Cg-TS, Cg-TEGS	$ 12.00	$ 0.3945	$ 0.1973	per Day	$ 6.00
Enhanced Administration Service		$ 37.50	$ 1.2329	$ 0.9205	per Day	$ 28.00
Volumetric Charges:						
Volumetric Local Distribution Service			$ 0.0927	$ 0.0910	per Therm	
Daily Balancing Service			$ 0.0005	$ 0.0005	per Therm	
**/ Cg-TSA, Annual Usage 5,000 - 20,000 therms*						
Commercial & Industrial Transportation Service - Annual Usage 20,001 - 200,000 therms						
Fixed Local Distribution Service		$ 150.00	$ 4.9315	$ 4.9315	per Day	$ 150.00
Enhanced Telemetering Service	Cg-TM, Cg-TEGM	$ 12.00	$ 0.3945	$ 0.1973	per Day	$ 6.00
Enhanced Administration Service		$ 37.50	$ 1.2329	$ 0.9205	per Day	$ 28.00
Volumetric Charges:						
Volumetric Local Distribution Service			$ 0.0708	$ 0.0708	per Therm	
Daily Balancing Service			$ 0.0005	$ 0.0005	per Therm	
Commercial & Industrial Transportation Service - Annual Usage 200,001 - 2,400,000 therms						
Fixed Local Distribution Service		$ 620.00	$ 20.3836	$ 21.3698	per Day	$ 650.00
Enhanced Telemetering Service	Cg-TL, Cg-TEGL	$ 12.00	$ 0.3945	$ 0.1973	per Day	$ 6.00
Enhanced Administration Service		$ 37.50	$ 1.2329	$ 0.9205	per Day	$ 28.00
Metered Demand Service			$ 0.1475	$ 0.1475	per Therm of Demand	
Volumetric Charges:						
Volumetric Local Distribution Service			$ 0.0342	$ 0.0331	per Therm	
Daily Balancing Service			$ 0.0005	$ 0.0005	per Therm	
Commercial & Industrial Transportation Service - Annual Usage > 2,400,000 therms						
Fixed Local Distribution Service		$ 3,882.00	$ 127.6274	$ 121.8411	per Day	$ 3,706.00
Enhanced Telemetering Service	Cg-TSL, Cg-TEGSL	$ 12.00	$ 0.3945	$ 0.1973	per Day	$ 6.00
Enhanced Administration Service		$ 37.50	$ 1.2329	$ 0.9205	per Day	$ 28.00
Metered Demand Service			$ 0.1000	$ 0.1000	per Therm of Demand	
Volumetric Charges:						
Volumetric Local Distribution Service			$ 0.0215	$ 0.0209	per Therm	
Daily Balancing Service			$ 0.0005	$ 0.0005	per Therm	

Wisconsin Public Service Corporation
Summary of Present and Authorized Natural Gas Rates
For the Test Year 2016

TYPE OF SERVICE	CUSTOMER CLASS	Monthly Equivalent	PRESENT RATES	AUTHORIZED RATES		Monthly Equivalent
Base Average Cost of Gas						
Commodity ("Comm") Rate			$ 0.4412	$ 0.4412	per Therm	
Peak Day Demand ("D1") Rate			$ 0.1226	$ 0.1226	per Therm	
Annual Demand ("D2") Rate			$ 0.0098	$ 0.0098	per Therm	
Balancing ("Bal") Rate			$ 0.0050	$ 0.0050	per Therm	
Act 141 Volumetric Distribution Rates †						
Residential			$ 0.0071	$ 0.0065	per Therm	
Commercial & Industrial (0 - 2,000 therms)			$ 0.0063	$ 0.0055	per Therm	
Commercial & Industrial (2,001 - 20,000 therms)			$ 0.0063	$ 0.0055	per Therm	
Commercial & Industrial (20,001 - 200,000 therms)			$ 0.0063	$ 0.0055	per Therm	
Commercial & Industrial (200,001 - 2,400,000 therms)			$ 0.0063	$ 0.0055	per Therm	
Commercial & Industrial (> 2,400,000 therms)			$ 0.0063	$ 0.0055	per Therm	
Interruptible Electric Generation			$ 0.0063	$ 0.0055	per Therm	

†/ Act 141 volumetric distribution rates are included in the above Volumetric Local Distribution Service Charges

TYPE OF SERVICE	CUSTOMER CLASS	Monthly Equivalent	PRESENT RATES	AUTHORIZED RATES		Monthly Equivalent
SEERA Refund Credit ‡						
Residential	Rg-3		$ -	$ (0.0008)	per Therm	
Commercial & Industrial (0 - 2,000)	Cg-FST		$ -	$ (0.0008)	per Therm	
Commercial & Industrial (2,001 - 20,000)	Cg-FS		$ -	$ (0.0006)	per Therm	
Commercial & Industrial (20,001 - 200,000)	Cg-FM		$ -	$ (0.0006)	per Therm	

‡/ SEERA Refund Credits are included in the above Volumetric Local Distribution Service Charges and sunset on December 31, 2016

Appendix D

Wisconsin Public Service Corporation
2016 Monitored Fuel Costs
6690-UR-124

MONTH	NET KWH PRODUCED	FUEL	MONTHLY FUEL COST PER NET KWH PRODUCED	CUMULATIVE COST PER NET KWH PRODUCED
JANUARY	1,194,230,908	$31,782,427	$0.02661	$0.02661
FEBRUARY	1,127,377,055	$28,604,255	$0.02537	$0.02601
MARCH	1,145,382,222	$29,726,952	$0.02595	$0.02599
APRIL	1,087,668,130	$30,010,714	$0.02759	$0.02637
MAY	1,107,915,053	$29,853,261	$0.02695	$0.02649
JUNE	1,192,693,073	$31,039,418	$0.02602	$0.02641
JULY	1,273,294,748	$33,326,093	$0.02617	$0.02637
AUGUST	1,246,310,856	$32,929,524	$0.02642	$0.02638
SEPTEMBER	1,146,138,162	$30,073,626	$0.02624	$0.02636
OCTOBER	1,114,578,098	$30,611,602	$0.02746	$0.02647
NOVEMBER	1,108,510,076	$28,892,321	$0.02606	$0.02643
DECEMBER	1,156,614,764	$31,191,336	$0.02697	$0.02648
TOTAL	**13,900,713,145**	**$368,041,530**	**$0.02648**	

Wisconsin Public Service Corporation
Deferral Amortization Schedule

Deferral	PSCW Deferral Authorization	Notes	Amortization Period	Test Year Amount Electric	Test Year Amount Gas
DePere Energy Center Premium	6690-EB-104	4	2016-2023	2,280,420	0
Domestic Manufacturing Deduction and Research & Experimentation Tax Credits	6690-GF-115 6690-UR-119	4	2016	75,687	0
Domestic Manufacturing Deduction and Research & Experimentation Tax Credits	6690-GF-115 6690-UR-119	4	2016	(673,793)	0
Tax Deferrals	Precedent	4	2016	(244,976)	(131,671)
Farm Re-Wiring Escrow	6690-UR-121	1	2016	1,000,000	0
Farm Re-Wiring Escrow Amortization Adjustment	6690-UR-121	1	2016-2017	(289,829)	0
Conservation Escrow (pre-Act 141)	Various	3	2016	1,900,800	475,200
Conservation Escrow (Act 141)	Various	1	2016	14,145,421	3,936,007
Conservation Escrow Amortization Adjustment	Various	3	2016-2017	299,903	(1,130,748)
Manufactured Gas Plant Cleanup	6690-UR-110	2	2016-2017	0	4,044,736
DSI Pre-certification-Edgewater	6690-GF-118	4	2016	234,888	0
Crane Creek Production Tax Credits (Shift to Grants)	6690-UR-121	3	2016-2039	800,093	0
Glenmore Wind Asset Retirement	6690 (1/10/13 Accounting letter PSC Ref #178828)	4	2016	108,158	0
Crane Creek - Depreciation Deferral	6690-UR-122	4	2016-2039	(344,796)	0
Fox Energy Center - Purchased Power Contract Buyout	6690-EB-105	4	2016-2022	5,340,528	0
Fox Energy Center - Deferred Revenue Requirement	6690-EB-105	1	2016-2018	3,808,948	0
Fox Energy Center - Utility Acquisition Adjustment	6690-EB-105	3	2016-2038	1,790,574	0
Fox Energy Center - Contract Service Agreement	6690-EB-105	3	2016-2020	2,195,364	0
Plant Abandonment Pulliam 5/6 & Weston 1	6690-UR-123	4	2016-2022	1,540,668	0
EPA Notice of Violation-Pulliam & Weston	6690-GF-126	4	2016	490,427	0
EPA Notice of Violation-Columbia & Edgewater	6690-GF-126	4	2016	486,029	0
SEERA Credit (Focus on Energy Refund)	6690-UR-124	1	2016	(1,116,703)	(279,176)
Totals				$ 33,827,810	$ 6,914,348

(1) Amount applies to Wisconsin Retail customers only.
(2) Amount allocated between Wisconsin and Michigan Retail customers.
(3) Amount allocated between all WPSC jurisdictions. (WI, MI, FERC)
(4) Amount allocated between Wisconsin Retail and FERC Market Based customers.

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates — 6690-UR-124

CONCURRENCE AND DISSENT OF COMMISSIONER MIKE HUEBSCH

While I concur with the agreed upon revenue requirement, I disagree with the Commission's determination on the authorized return on common equity (ROE). Although Wisconsin has taken a step in the right direction by lowering the ROE to 10.0 percent from 10.2 percent, I believe it is too small a step in relation to the record from across the industry and across the country.

In his direct testimony, Mr. Steve Chriss of Wal-Mart offers compelling evidence for a lower ROE, presuming the goal is to provide Wisconsin Public Service Corporation (WPSC) only the minimum amount necessary to provide adequate and reliable service, while earning a reasonable return.

The average authorized ROE approved by state regulatory commissions to investor-owned utilities in 2012, 2013, 2014 and so far in 2015 is 9.86 percent. And for vertically integrated utilities since 2012 is 9.99 percent; however, the trend has been in sharp decline. In 2012, the average ROE was 10.1 percent, in 2013, 9.97 percent, in 2014, 9.91 percent and so far in 2015, 9.72 percent. The trend indicates that the 2015 average will decline even further before year's end.

In addition, when reviewing 2014 data, the average ROE authorized in Wisconsin was 43 basis points above the national average for vertically integrated electric utilities and 64 basis points above the average for natural gas utilities.

In the interest of ratepayers and of keeping Wisconsin's energy prices competitive, a reduction to 9.75 percent, or 45 basis points below WPSC's request is prudent, is incremental in a way to diminish the impact upon the company's ability to attract capital and more closely reflects the current market.

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